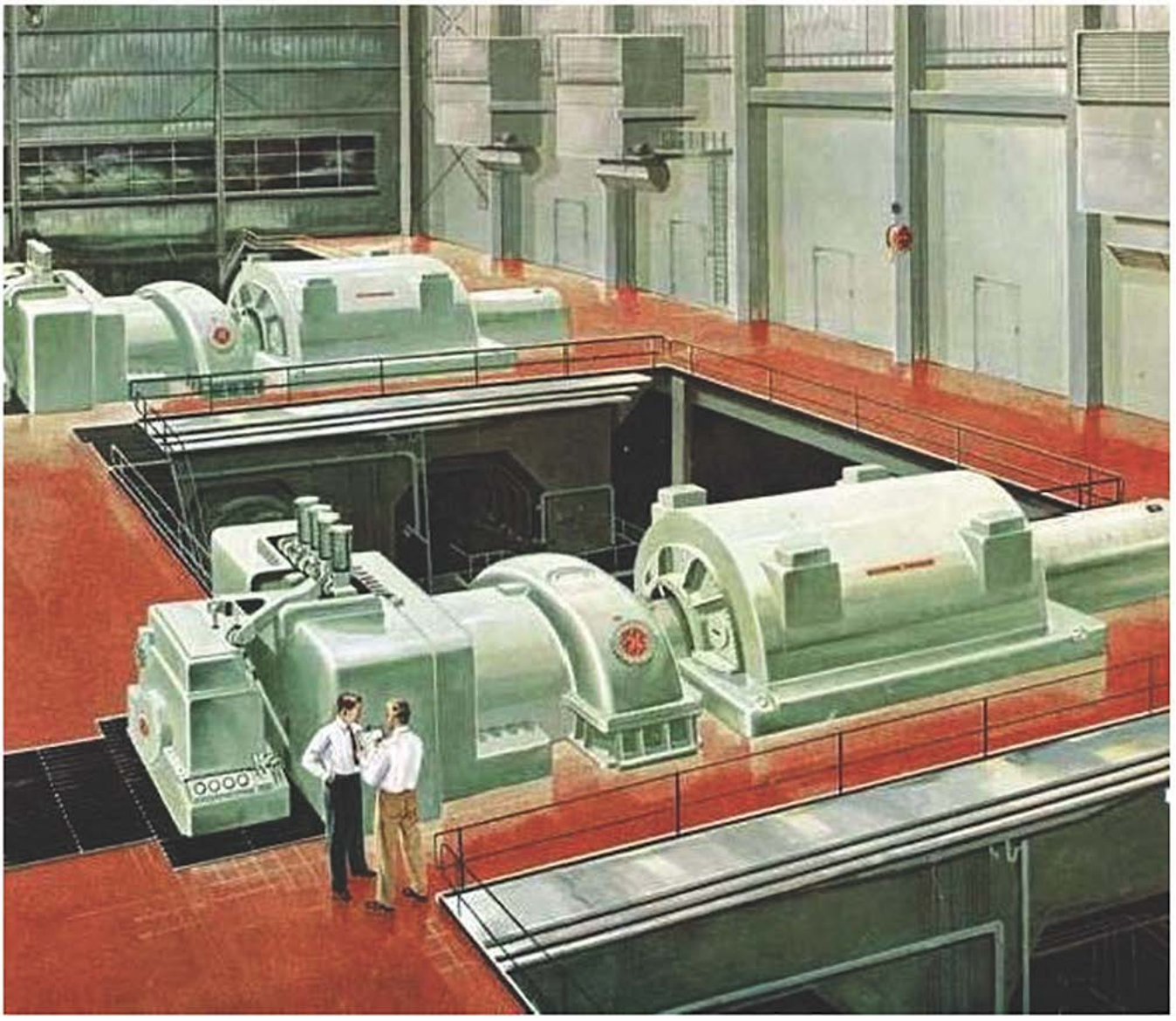
# Steam Turbines for Stationary Engineers



# Steam Turbines
## Chapter1
### Turbine Theory
### TURBINE HISTORY and DESIGN PRINCIPLES

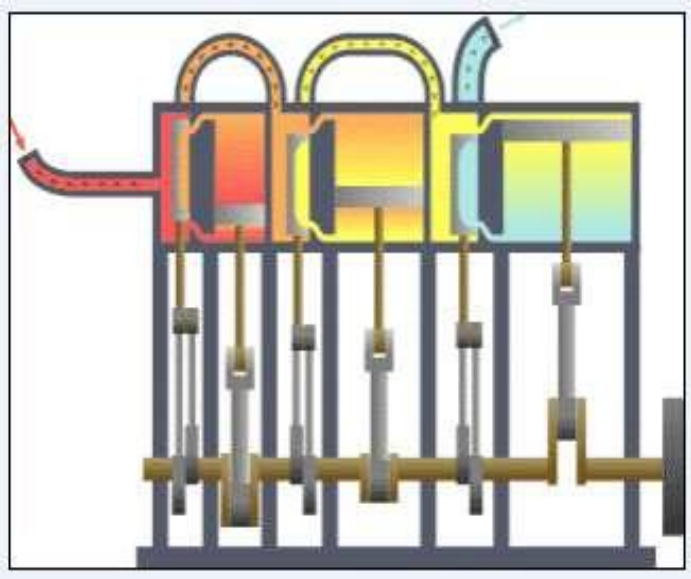


Figure 1. Triple Expansion Steam Engine

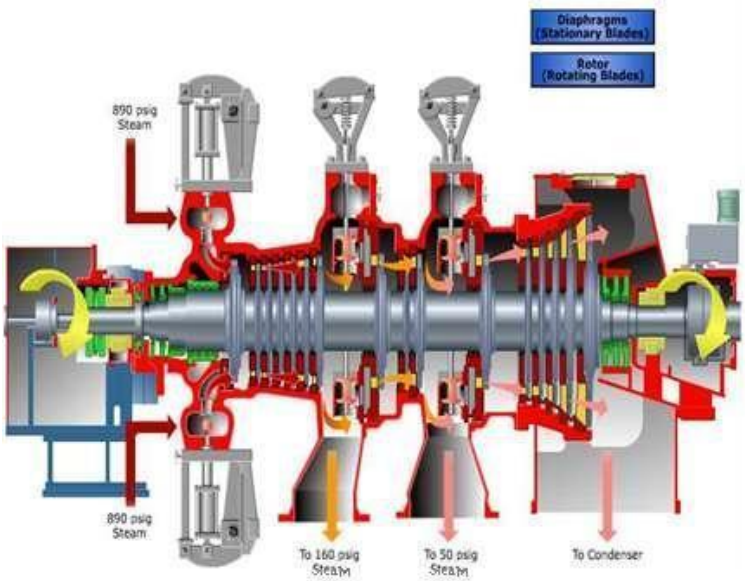



Figure 2. Steam Turbine with three exhaust ports

## 1. What is a Heat Engine?

A heat engine is a device that converts heat energy to mechanical energy. The steam turbine is classed as a heat engine as is the steam engine. The velocity attained during expansion of the steam depends upon the initial and final heat content of the steam. The difference in heat content represents the heat energy converted to kinetic energy. The turbine makes use of the fact that steam when issuing from a small opening attains a high velocity. The kinetic energy or work available in the steam leaving a nozzle is equal to the work that the steam could have done had it been allowed to expand (with the same heat loss) behind a piston in a cylinder. In the steam turbine the heat energy is converted to kinetic energy as the steam expands through the turbine.

*Steam Plant Operation by Woodruff and Lammers 5th Edition. page 437*
*Detroit Edison Steam Course Single Valve Steam Engines page 1*

## 2. Name two (2) types of heat engines:

The Steam Turbine and the Steam Engine

*W&L 5th page 437*

Figure 3. Modern Turbine Room

## 3. What are advantages of using steam turbines over reciprocating engines?

Smooth or constant torque characteristics simplify the operation and maintenance of turbines, as compared with reciprocating engines. Turbines can be built more economically in larger sizes; hence they are quite suitable for large electrical generating powerplants. Oil is not directly mixed with steam and no internal lubrication is required for steam turbines due to the absence of rubbing parts. Steam can be withdrawn at different stages for process work, increasing the heat balance of the plant. Disassembly for repair is easier as the shell is unbolted and the upper casing removed with an overhead crane for access to the rotor. Steam engines require more complicated disassembly. Wear on a turbine casing is negligible while steam engine cylinders need to be rebored periodically. Turbines can run for longer periods before needing to be overhauled. Steam turbines have higher thermal efficiency than reciprocating steam engines. Unlike reciprocating engines, the turbines do not need any flywheel. High speeds, l,800 rpm to 24,000 rpm can be developed in steam turbines but such speeds are not possible in the case of large reciprocating steam engines. In a reciprocating steam engine, the pressure is directly used to move the piston and the load to which it is attached. The use of the kinetic energy of the steam is small in comparison to a turbine.

*Steam and Gas Turbines by Bernhardt G. A. Skrotzki, and William A. Vopat 1950 page 13*

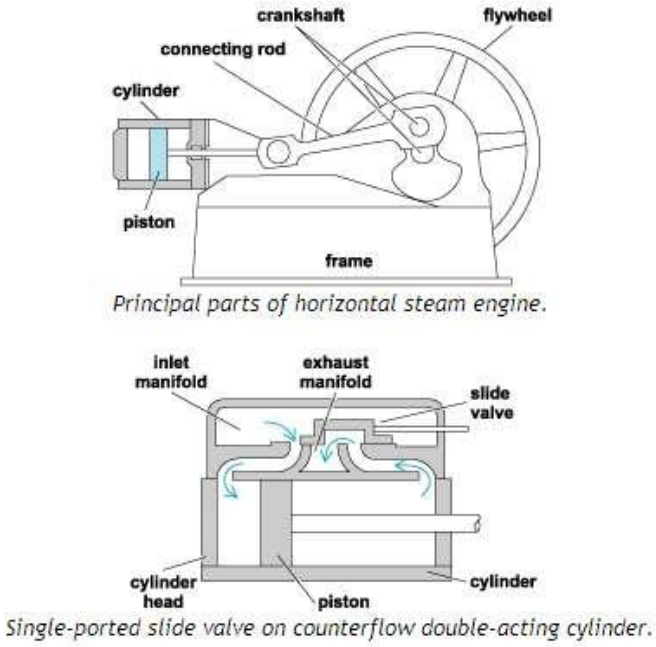



Figure 4. D-Slide Valve Steam Engine

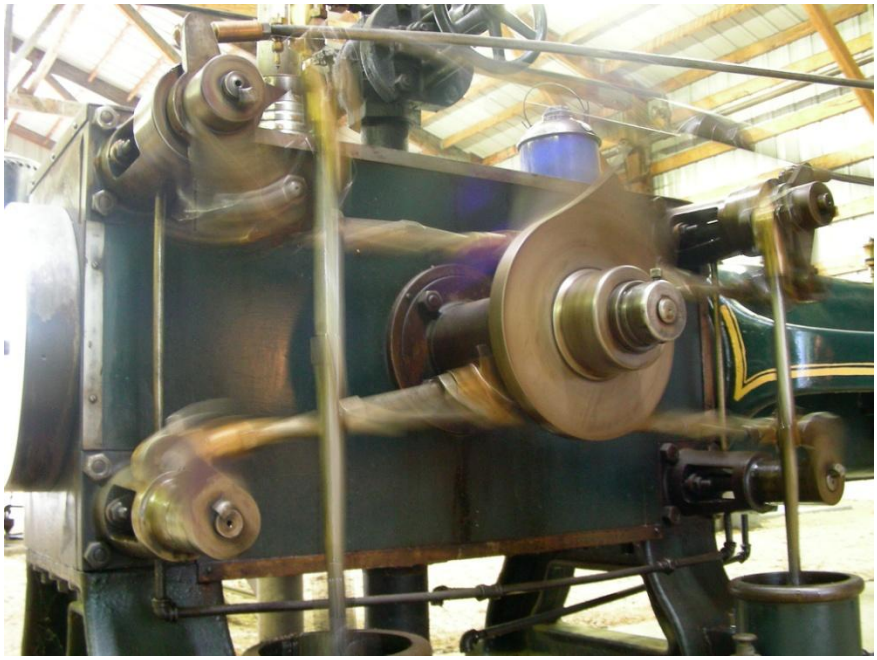


Figure 5. Corliss Steam Engine in operation

## 4. When is it better to use a steam engine over a steam turbine?

The chief application of the condensing steam engine is for electric power plants which have a limited supply of water, and for driving slow moving machinery which cannot be turbine driven. Steam engines are better for applications where there will be a lot of starting and stopping of driven equipment.

*Terrell Croft Steam Engine Principles and Practice 2nd Ed. page 290*

Figure 6. Destroyed steam turbine blading

## 5. What is the difference between excessive carryover to reciprocating engines and carryover to steam turbines?

Because water is non-compressible, an excessive amount of water in the cylinder of a steam engine will cause the head to blow off the engine and/or destroy the piston and connecting rod. Excessive water carryover in a turbine will erode the blades and may cause the blades to break off and fly through the casing.

## 6. What is a good definition of a steam turbine?

A steam turbine is a prime mover. In this case the prime mover is a machine that takes steam vapor and coverts the heat energy of the steam into mechanical work. By converting the heat energy of steam into kinetic energy as it expands through a series of nozzles mounted on the casing, a wheel or series of wheels attached to a rotor is made to turn, reducing the heat energy of the steam and lowering the pressure and temperature of the inlet steam.

*Boiler Operation Engineering by P Chattopadhyay page 856*

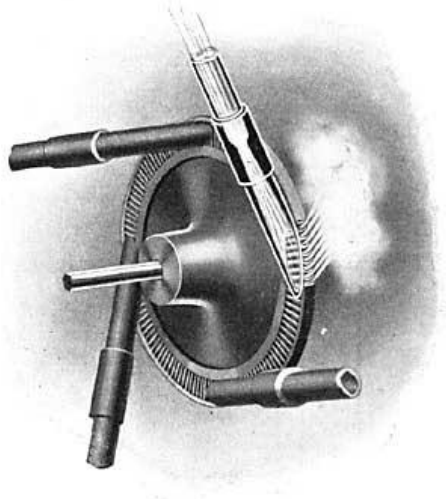


Figure 7. Impulse wheel with four nozzles

## 7. What is the operating principle of a steam turbine?

In an enclosed vessel such as a boiler, the fire in the boiler transmits heat to the water creating steam. Continued heating of the steam in the enclosed vessel increases its pressure because it is confined within the vessel. Each pound of water would expand 1600 times its original volume if not confined within the vessel. The heat content increases as heat from the fire is absorbed by the water in the boiler. Once the steam's thermal energy is released through a stationary nozzle, several things happen. The steam pressure is reduced, increasing steam volume. The steam velocity is increased as the high speed jet leaves the nozzle, and the temperature of the steam is reduced. The kinetic energy of the steam jet is converted to mechanical energy each time it hits the buckets of an impulse turbine or blades of a reaction turbine attached to a rotor causing it to spin. The direct relationship between the amount of heat and temperature loss in the turbine for the work performed is why it is known as a heat engine. High velocity steam blowing on a curved blade will cause a change in direction as it passes across the blade. As a result of this change in direction across the blade, the steam will impart a force to the blade. This force will cause the blade and the rotor to which it is attached to rotate.

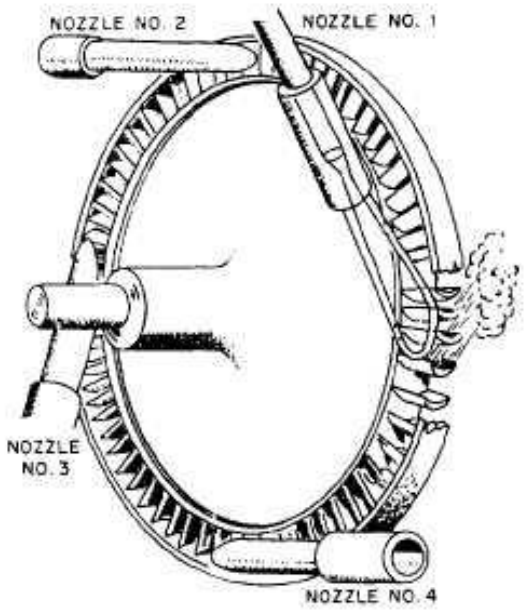



Figure 8. Impulse Principle

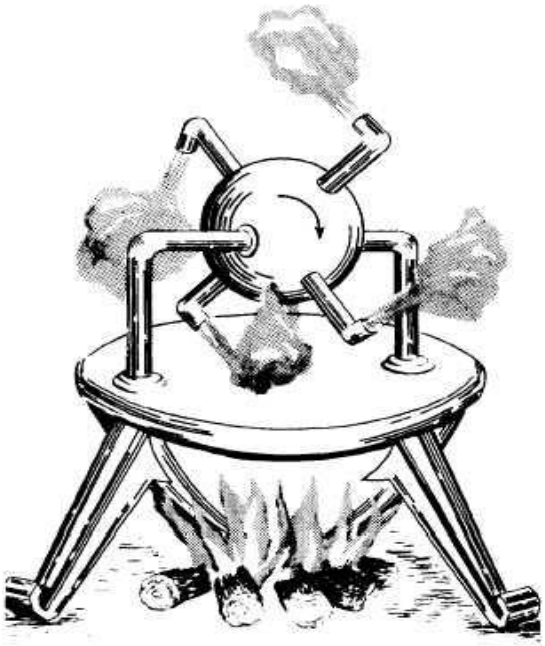


Figure 9. Reaction Principle

## 8. What are the two main principles upon which steam turbines operate?

Impulse and reaction

## 9. What is the reaction principle?

Steam issuing from a nozzle causes the wheel to which it is attached to move in the opposite direction. A reaction turbine is moved by three main forces: (1) the reactive force produced on the moving blades as the gas increases in velocity as it expands through the nozzle-shaped spaces between the blades; (2) the reactive force produced on the moving blades when the gas changes direction; and (3) the push or impulse of the gas impinging upon the blades. Thus, as previously noted, a reaction turbine is moved primarily by reactive force but also to some extent by direct impulse

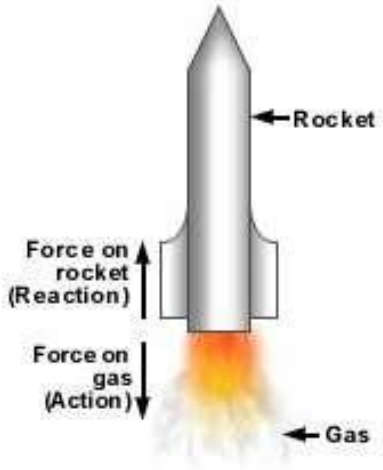



Figure 10. The rocket's burning gases push against the interior in all directions but it is only allowed to exhaust out the tail. The reaction force pushes against the nosecone and forces the rocket up. It does not push against the ground as some believe, otherwise it would not operate in space.

Figure 11. For every action there is an equal and opposite reaction. The total force pushing the shot out the barrel is transmitted to the shoulder of the shooter.

## 10. Give an example of a reaction force.

A good example of a reactive force would be a rocket that has exhaust gasses coming out the tail end, propelling the rocket in the opposite direction. Another example is the "kick" on your shoulder from shooting a shotgun.

*Terrell Croft Steam Turbine Principles and Practice, 2nd Edition 1940 page 5*

A reactive force or "reaction" is that force which is produced on an object when a fluid stream leaves the object at a greater velocity than that with which it approaches the object. You do not get something for nothing. The increase in velocity comes at the cost of a decrease in heat content and pressure inside the turbine.

Figure 12. Hero's turbine, also known as an aeolipile

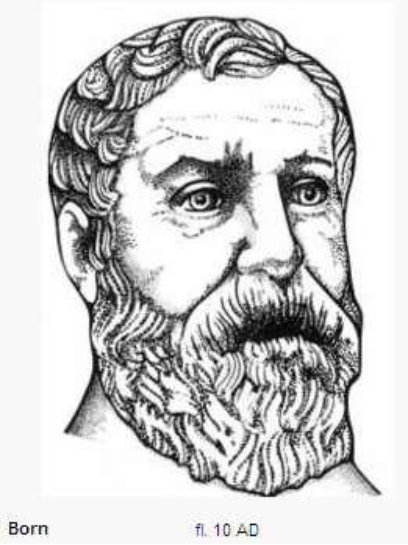



Figure 13. Hero of Alexandria

## 11. Who invented the first reaction turbine?

The earliest record of any heat engine is in a book written by Hero of Alexandria, probably about 150 B.C., in which a steam reaction wheel is mentioned. This turbine consisted of a sphere supported on opposite sides and nozzles, adjacent to the supports, with the outlets of these nozzles pointing in different directions. As the steam is delivered to the sphere through an opening in one of the supports, it is issued from the tips of the nozzles causing the sphere to rotate.

*Croft Steam Turbine Principles and Practice.2nd Edition.1940 page 1*

Figure 14. Impulse principle in action

## 12. What is the impulse principle?

Steam issuing from a stationary nozzle strikes blades at an angle on a wheel and causes the wheel to move in the same direction as the steam jet.

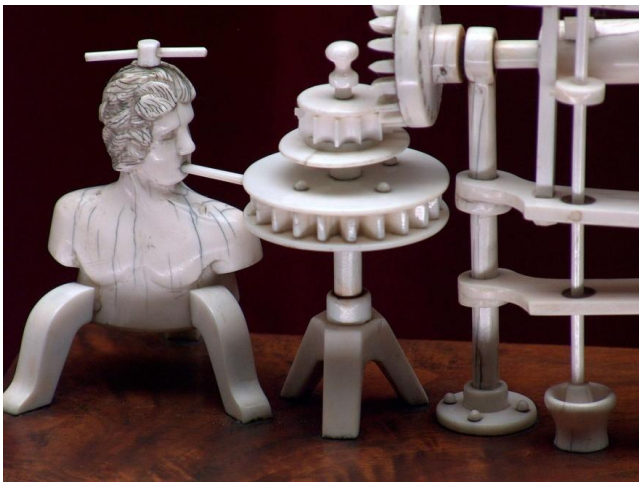


Figure 15. Master carver Ernest Warther's interpretation of Branca's Turbine

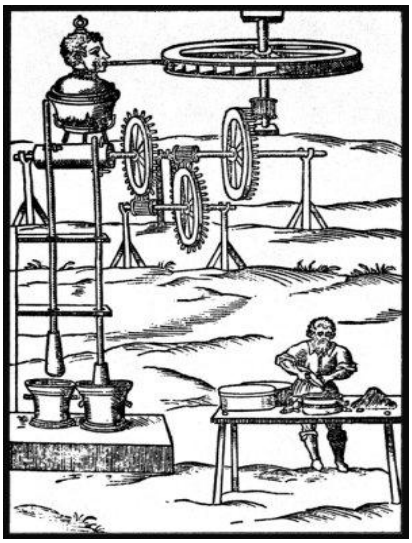


Figure 16. Lithograph of Branca's Turbine operating a mortar and pestle

**13. Who invented the first impulse turbine?**

Branca, an Italian architect, in 1629. This turbine consisted of the equivalent of a paddle wheel lying on its side with a boiler issuing steam from a tube directed at the paddlewheel causing it to rotate.

*Croft Steam Turbine Principles and Practice, 2nd Edition. 1940 page 2.*

Figure 17. Impulse blading is symmetrical and crescent shaped

Figure 18. Reaction blading is Teardrop shaped

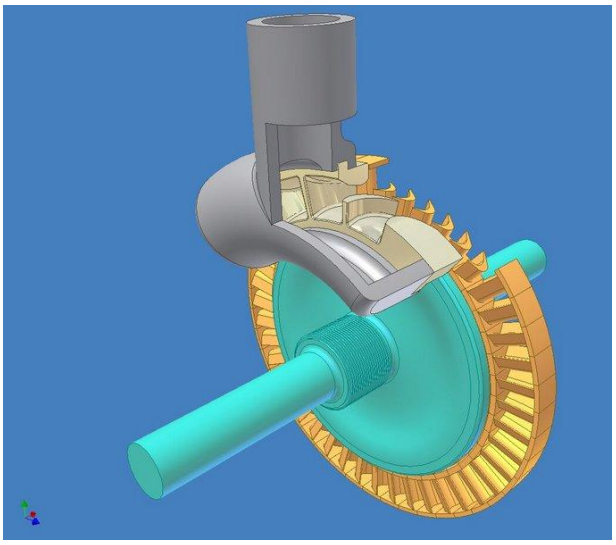


Figure 19. Impulse blading with convergent nozzle

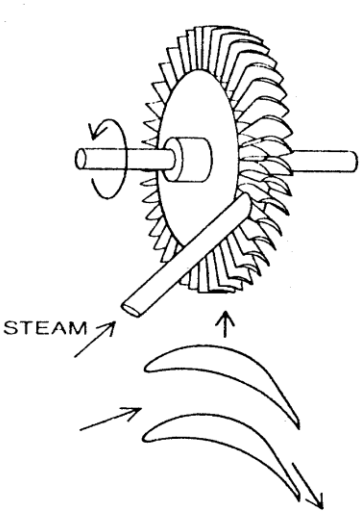



Figure 20. Reaction blading and profile of the blade ends

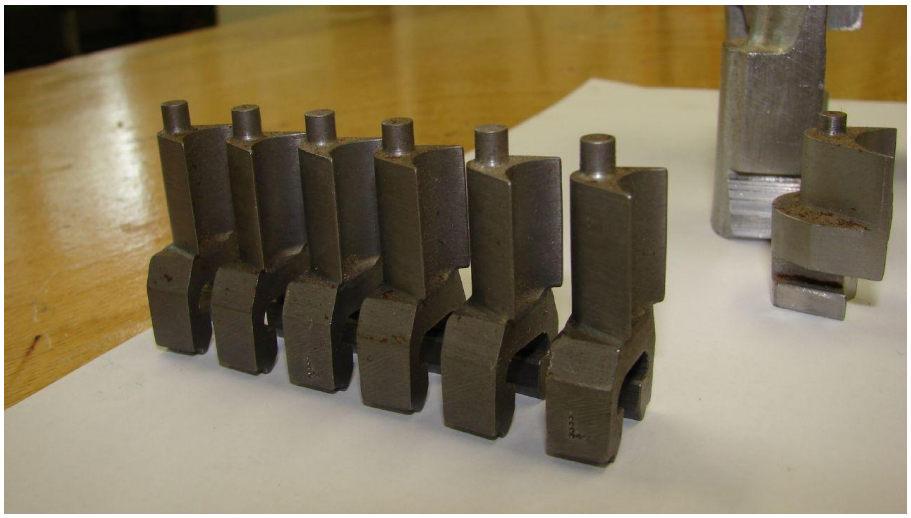


Figure 21. Impulse Buckets

Figure 22. Reaction Blade

### 14. How are impulse and reaction blades designated?

Though literature uses the term "blades" to refer to both impulse and reaction turbines, it is more correct for impulse turbines to use the term "buckets" while reaction turbines use the term "blades".

### 15. Why use curved blades in a turbine?

Curved blades are used on a turbine because the curved blade will produce more work than the flat blade. The steam stays in contact with the blade longer and it directs the steam to the next stage.

### 16. Why don't we use full half circles in designing impulse turbine blades?

A full half circle will not allow steam to enter the next stage efficiently.

### 17. What speed, in relation to the steam, is the bucket traveling in an impulse turbine?

This takes place when the bucket speed equals one-half the jet speed.

### 18. What is the ideal condition for a steam jet hitting the blades of a reaction turbine?

The ideal condition for a steam jet hitting the blades arises when the jet speed is the same as the blade speed.

### 19. What kind of energy does a steam jet have when moving?

When the steam jet moves it has kinetic energy.

### 20. Why do we have a high jet speed?

Because of the high steam pressure in the boiler that converts the pressure to a high speed steam jet in the nozzle. The steam jet is the kinetic energy that is converted into mechanical work to turn the turbine.

Figure 23. Karl Gustaf DeLaval

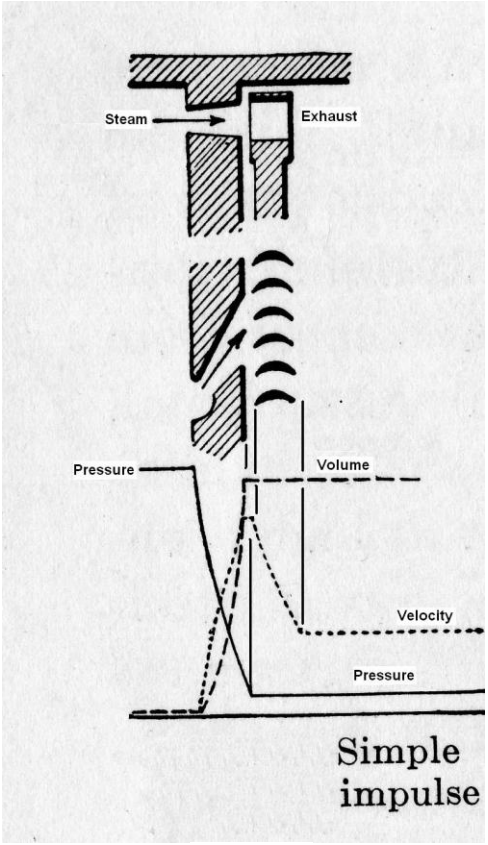



Figure 24.

**21. Give another name for a simple impulse turbine.**

The simple impulse turbine is also known as DeLaval staging. The steam enters through a convergent divergent nozzle and all of the expansion takes place in the nozzle. The steam velocity increases rapidly as the expansion takes place and the velocity at the exit of the nozzle is at its maximum. There is no expansion of steam in the moving buckets of the turbine; the steam is exhausted from the wheel at the same pressure with which it entered the wheel. However, the velocity of the steam is greatly reduced in passing through the buckets as the kinetic energy of the steam jet is converted to useful work. Turbines of this type have a very high rotative speed, (20,000 to 30,000 RPM)

*Elementary Steam Power Engineering Edgar McNaughton page. 457*

**22. In the stationary nozzle of an impulse turbine, what happens to the pressure?**

The pressure goes down.

**23. In the stationary nozzle of an impulse turbine, what happens to steam volume?**

The steam volume increases.

**24. In the stationary nozzle of an impulse turbine, what happens to the velocity?**

The velocity goes up.

**25. In the moving buckets of a simple impulse turbine, what happens to the pressure?**

The pressure remains the same.

**26. In the moving buckets of a simple impulse turbine, what happens to the velocity?**

The velocity goes down.

## 27. What are disadvantages of simple impulse (DeLaval) turbines?

Since the whole pressure drop from boiler to condenser pressure takes place in a single row of nozzles, the velocity of the steam entering the turbine is very high. If some of this velocity is used up in a single row of turbine blading, as in the DeLaval turbine, the speed of the rotation of the wheel will be too high to be useful for most practical purposes. DeLaval style turbines are used in centrifuges and other high speed applications. Steam exits from the turbine with a high velocity, meaning a considerable loss of kinetic energy.

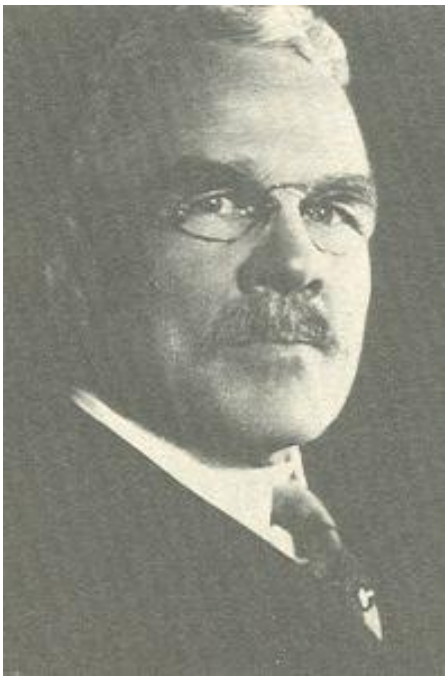


Figure 25. Charles Gordon Curtis

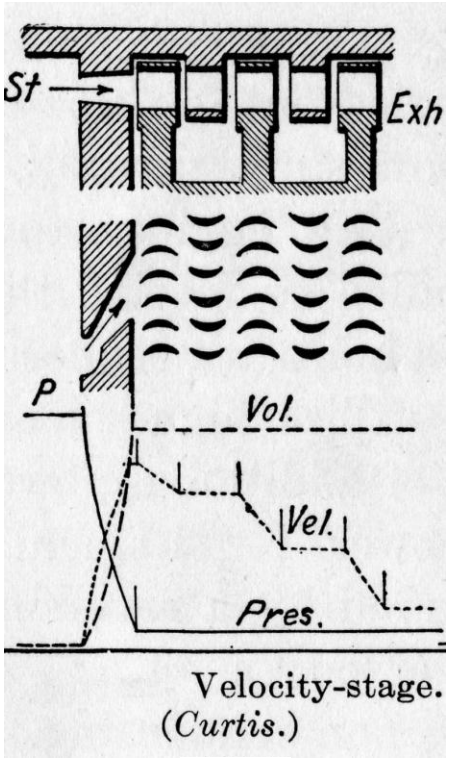



Figure 26.

## 28. Give another name for a velocity compounded impulse turbine.

This is known as Curtis staging. In this type turbine the total expansion of the steam takes place in one step, in the nozzles ahead of the first row of moving buckets. The reduction in the velocity of the steam is accomplished in two or more steps, however, making it possible to have slower shaft speeds. The stationary blades between the rows of moving buckets act only as guide vanes to change the direction of flow, and they do not alter either the pressure or the velocity of the steam. This turbine is called an "Equal Pressure Turbine" because the pressure stays the same through the reversing and rotating buckets. Velocity is reduced in the revolving buckets and remains the same in the stationary buckets.

*The Detroit Edison Steam Course, Turbines. p. 15*

## 29. What is velocity compounding on an impulse turbine?

Velocity compounding has two or more rows of moving blades which allow the use of slower blade speeds. Each moving row absorbs part of the jet energy.

### 30. Why is velocity compounding used on an impulse turbine?

To get more work from the steam and slow down the turbine rotor.

### 31. How is velocity compounding achieved on an impulse turbine?

By redirecting the steam through reversing buckets to enter the same wheel or another wheel depending upon the design of the turbine.

### 32. What are the advantages of velocity compounding on an impulse turbine?

The velocity compounding system is easy to operate and operation is more reliable.

Only two or three reversals are required. Since the total pressure drop takes place only in nozzles and not in the buckets, the turbine casing is lighter than a comparable pressure compounded turbine. It costs less to build. Less floor space is required.

### 33. What are the disadvantages of velocity compounding on an impulse turbine?

Steam velocity is high and causes more friction losses. With the increase in the number of rows of buckets, the power developed in successive row of buckets decrease. Since the same space and material are required for each row of buckets, all stages are not equally efficient.

### 34. Where are velocity compounded impulse turbines usually employed?

They are chiefly used as the prime mover for:

A.) Centrifugal pumps.

B.) Centrifugal compressors.

C.) Low capacity turbo-generators.

D.) Feed pumps of high capacity power plants.

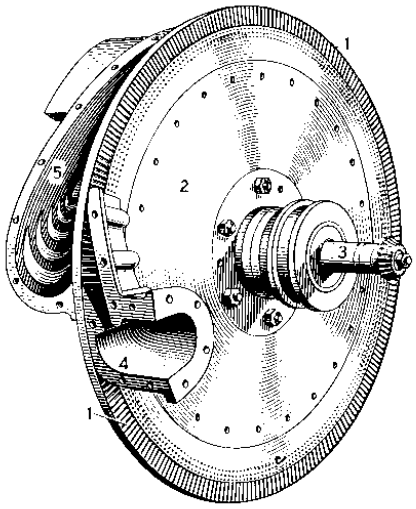
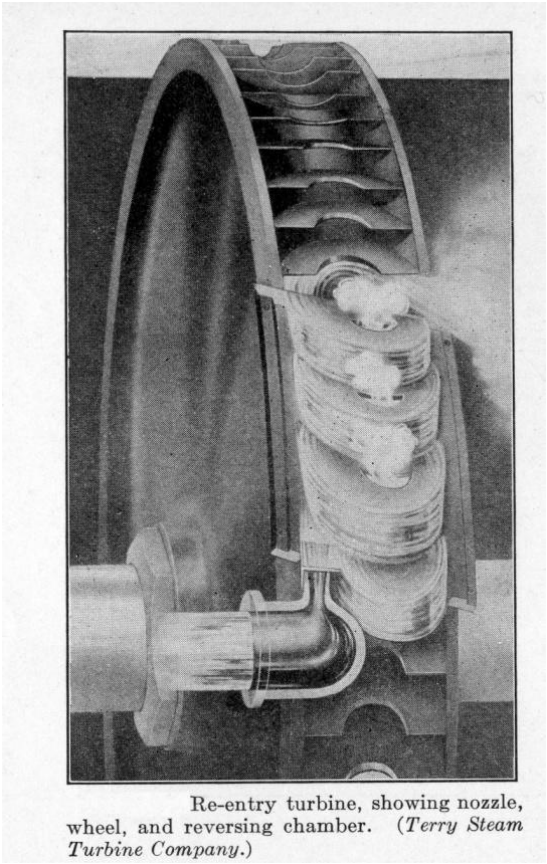



Figure 27. Reentry turbine. 1 is the buckets, 2 is the disk, 3 is the rotor 4 is the nozzle, and 5 is the reversing chamber .

### 35. Velocity compounding can be obtained by use of the reentry principle. What type of arrangement is this?

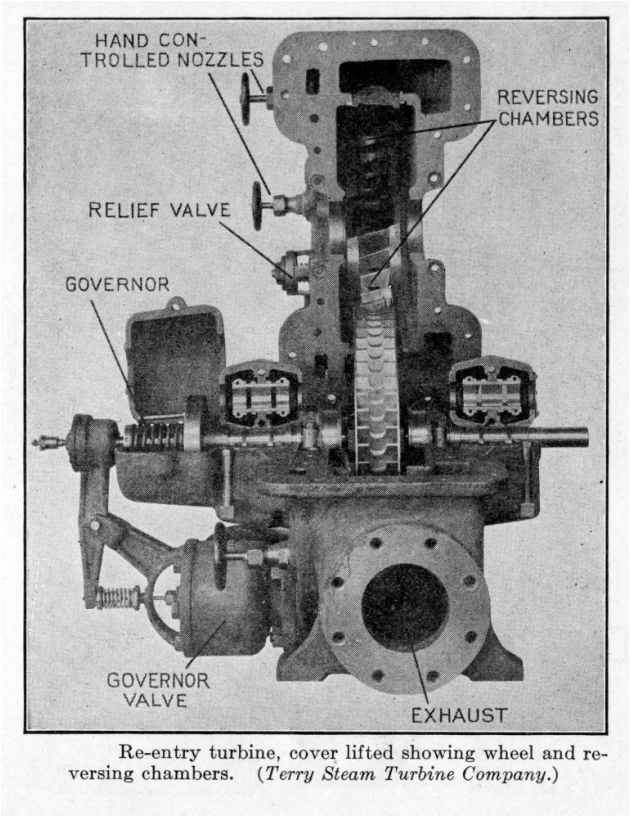
Velocity compounding may be obtained with a single row of moving buckets by use of the reentry principle. Nozzles for these designs are commonly part of a reversing chamber assembly which redirects steam back through buckets on the same wheel.

*S&V pages 41-42*



Re-entry turbine, showing nozzle, wheel, and reversing chamber. (*Terry Steam Turbine Company.*)

Figure 28.




Re-entry turbine, cover lifted showing wheel and reversing chambers. (*Terry Steam Turbine Company.*)

Figure 29. This turbine was invented by Edward Clinton Terry in the late 1800's.

**36. How do you achieve velocity compounding of radial flow turbine like a Terry turbine?**

In this type the turbine has a solid wheel, and the buckets are milled out of the rim. Steam flows from the nozzle radially and is redirected by reversing chambers located in the case. The steam flows in a corkscrew fashion.

**37. In the stationary reversing buckets of an impulse turbine, what happens to pressure?**

The pressure remains the same.

**38. In the stationary reversing buckets of an impulse turbine, what happens to velocity?**

Velocity remains the same.

**39. What happens to steam pressure and speed going through velocity compounded impulse staging?**

Higher steam speeds can be developed in the nozzle of a velocity compounded impulse stage. Steam pressure stays constant through all sets of moving buckets and stationary reversing buckets.

**40. In small impulse turbines, reversing buckets are required around how much of the periphery of the wheel?**

Since the steam to an impulse turbine is delivered only over a portion of the periphery, reversing blades are required across from the nozzles only.

*Kents. 11th Edition. pages 8-04. 8-05*

Figure 30. Auguste Camille Edmond Rateau

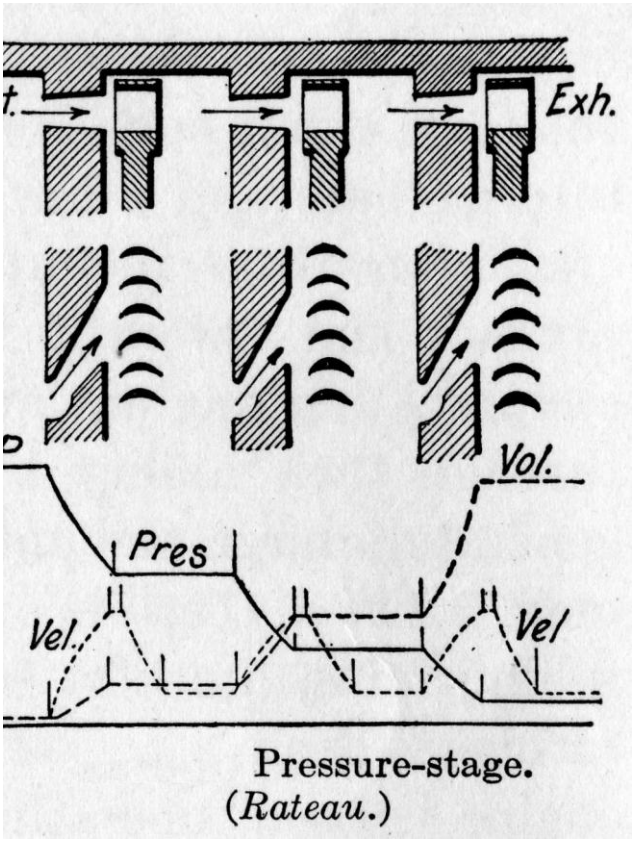



Figure 31.

**41. Give another name for a pressure compounded impulse turbine.**

This is known as Rateau staging. In this type of machine the expansion of steam takes place in two or more steps. The relationship between the pressure and the velocity of the steam in the individual nozzles is exactly the same as in the simple impulse turbine. The difference being that the expansion from throttle pressure to exhaust pressure is carried out in two or more stages or steps.

*The Detroit Edison Steam Course, Turbines p. 14*

**42. Explain pressure compounding.**

When steam expands from a high pressure, one method of keeping velocities within practical ranges is to expand the steam in two or more stages. This is known as pressure compounding.

**43. What is pressure compounding?**

Pressure compounding has two or more sets of nozzles in series which drop steam pressure.

**44. How does pressure compounding differ from velocity compounding?**

Velocity compounding simply redirects the steam jet. Pressure compounding goes through another stationary nozzle to increase steam velocity while lowering steam pressure.

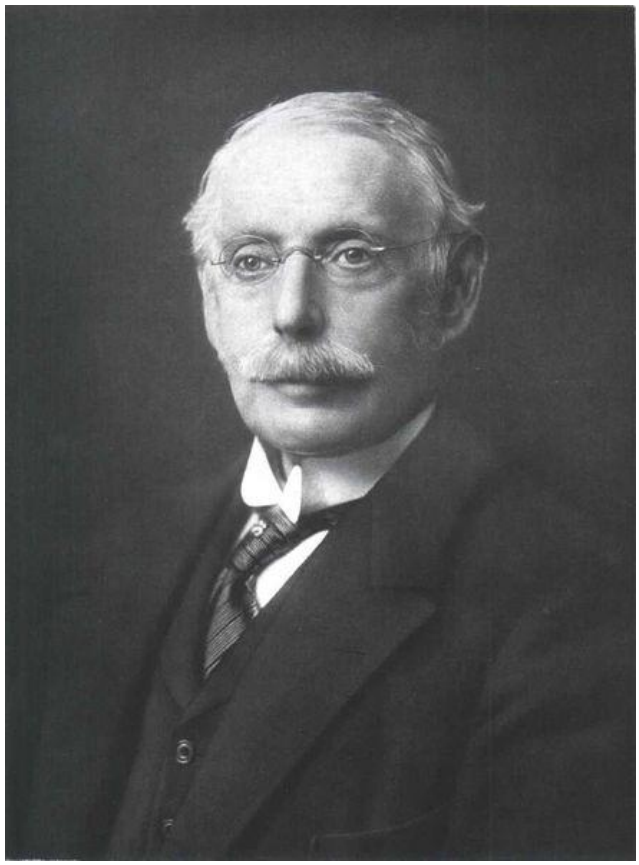


Figure 32. Sir Charles Algernon Parsons

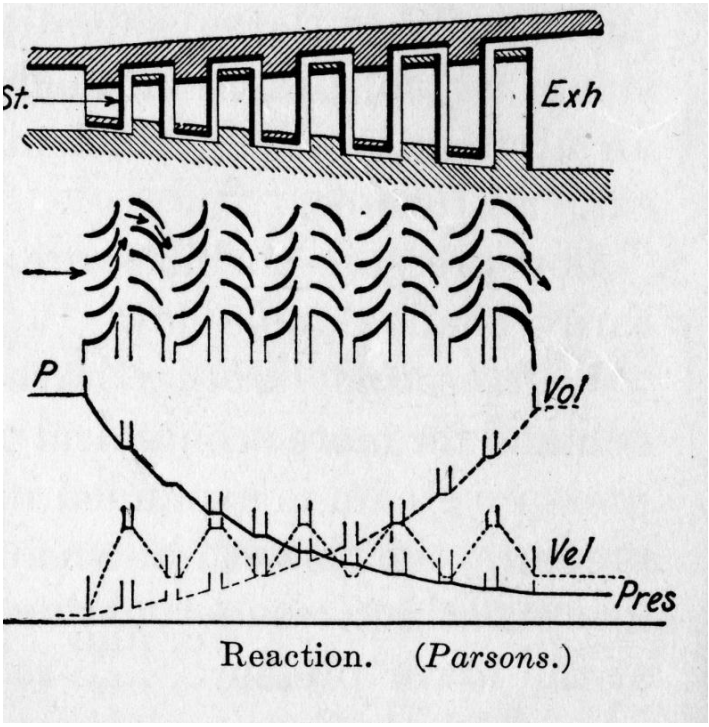



Figure 33.

**45. Give another name for a reaction turbine.**

This type of turbine is known as a Parsons turbine. It is also known as a pressure compounded turbine since it loses pressure in both the moving and stationary blades. The blades act as nozzles. In the stationary nozzles pressure is reduced as velocity is increased. In the moving nozzles, pressure and velocity are decreased. Pure reaction turbines require steam to be admitted to the entire periphery of the wheel

*S&V page 175*

**46. What is the difference between the look of reaction blading and impulse buckets? .**

The blade cross-section differs due to the differing functions of the blading. Since no expansion of steam takes place in the buckets of an impulse turbine, the pressure of the steam is very nearly the same at the inlet as in the outlet of the moving blades. Therefore, the passage between adjacent blades has a uniform (crescent-shaped) cross-section from the inlet to the outlet side.

In a reaction turbine, the steam expands as it travels through the moving and the stationary blades: therefore, it exits from each set of blades at a lower pressure than that at which it entered. To take care of this continuous expansion of the steam, the passage between adjacent blades in a row, whether of stationary or moving blades, increases in area of (teardrop shaped) cross-section toward the outlet side.

*D.E.S.C. Simple Turbines p.21*

## 47. What is a stage in a steam turbine?

Whenever steam goes through a nozzle or a blade that acts as a nozzle, pressure drops. That is considered a stage.

In a Curtis turbine with one set of nozzles, it is considered to be a single stage even though it can have any number of moving buckets on wheels and stationary buckets that act to redirect the steam flow into the next set of moving buckets.

In a reaction turbine, each set of moving or stationary blades reduce pressure so all the sets of blades are considered stages.

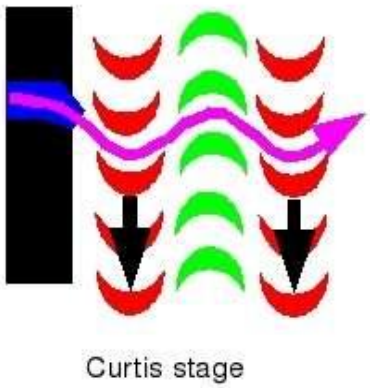



Figure 34.

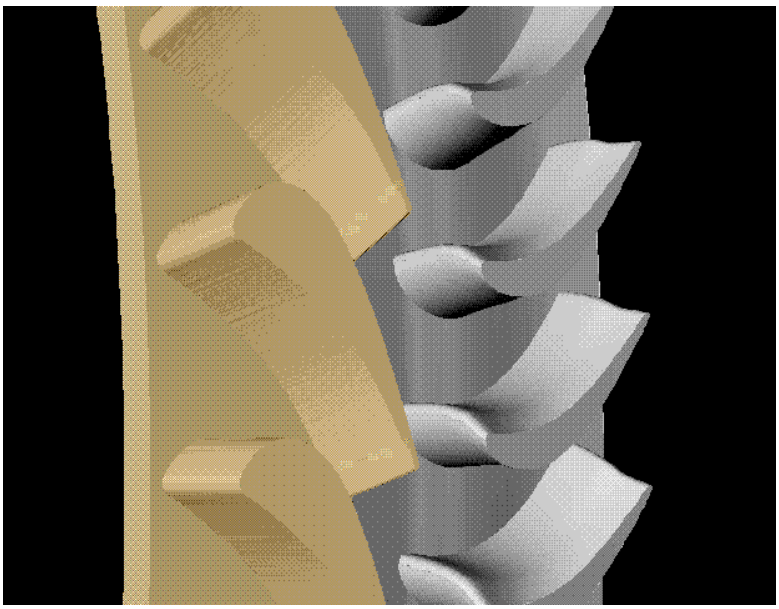


Figure 35. Reaction Turbine Stage

## 48. What do we mean by full periphery of the wheel?

Full periphery of the wheel means the full outside edge or perimeter of the wheel.

## 49. What type of inlet valve is used on a pure reaction turbine?

A single inlet valve that allows steam to enter the full periphery of the first set of stationary nozzles.

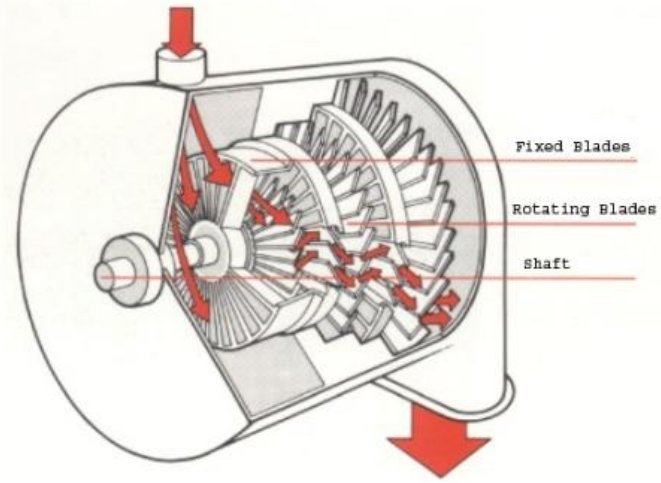



Figure 36. Single inlet valve allows steam to enter around 100% of the first wheel

## 50. Are all pure reaction turbines always pressure compounded?

Yes. Pressure is reduced through both moving and stationary blades.

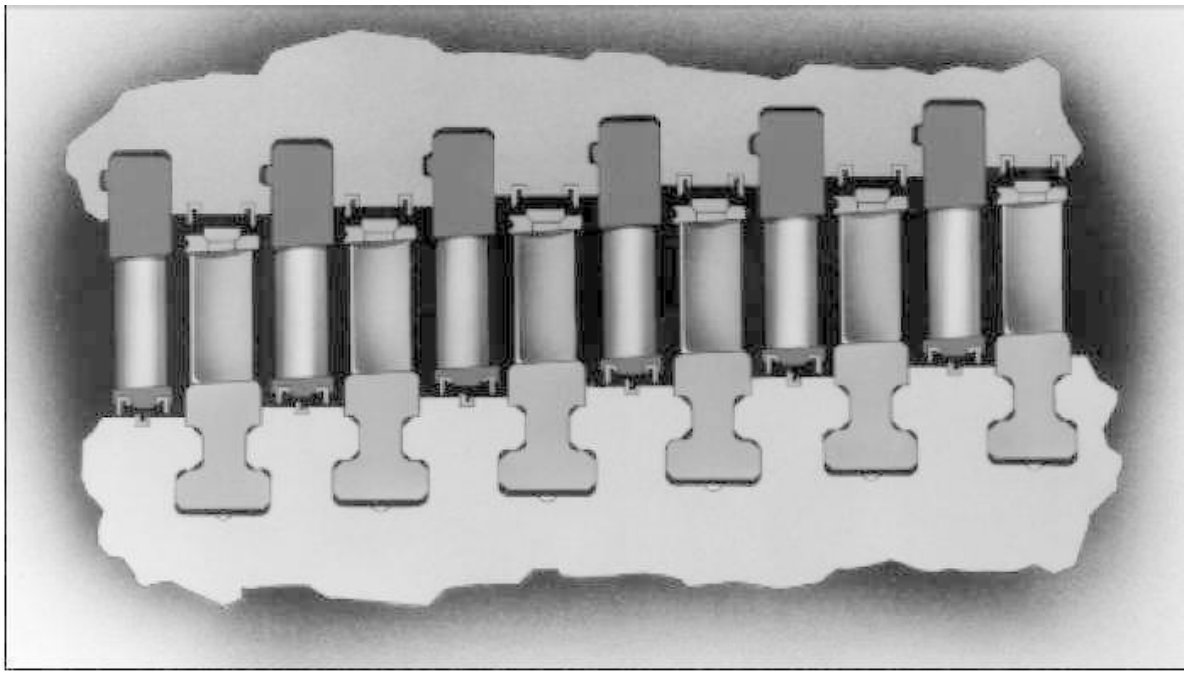
Reaction turbines use both stationary and moving nozzles. The blades are actually nozzles mounted on the rotor between each set of moving nozzles in a stationary set of nozzles. In stationary nozzles pressure is reduced as velocity increases In the moving nozzles pressure and velocity are both decreased. Steam pressure drops in both stationary and moving blading of a reaction turbine. All reaction turbines are pressure compounded.

*McNaughton page 457*

*S &V page 175*

## 51. In which turbine is tip leakage a problem?

Tip leakage is a problem in reaction turbines. Here, each vane forms a nozzle; steam must flow through the moving nozzle to the fixed nozzle. Steam escaping across the tips of the blades represents a loss of work. Tip seals are used prevent this.



Typical reaction stages, drum rotor construction

Figure 37. Shows tip seals at the ends of the blades and the diaphragms to help stop steam leakage between stages

## 52. Why do most large reaction turbines have the first two stages impulse?

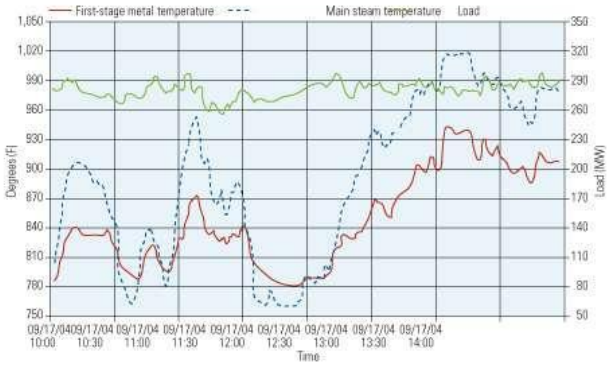
In a pure reaction turbine the only means of controlling output is to raise and lower the pressure of the steam entering the first stage blading as a result of opening and closing the governor controlled inlet valve. However, better steam control with more efficient utilization of steam energy at low loads can be secured by the partial admission design of the first stage of impulse turbines. Also, by using a velocity compounded impulse stage for the first one in a turbine, the length of the unit can also be shortened. Hence, it will be found that most reaction turbines use such a stage as the initial one.

*S&V pages 174-175*

Figure 38. The first two stages are Curtis impulse stages and the other stages are reaction stages. The technician is inserting reaction blading with integral shrouding into the third stage of the turbine.

## 53. What effect do load increases have on turbine temperatures?

After the first stage nozzles, temperatures rise as the turbine load increases




**One day at a time.** Load, turbine first-stage temperature, and superheat temperature during dispatch of Sim Gideon Unit 3 on a typical day. Source: LCRA

Figure 39. Chart showing the temperature rise in red as the load on the turbine increases in blue.

## 54. What is the limiting factor in regards to the temperatures and pressures that a turbine can withstand?

The nature of the metals of which turbines are made represents a real limitation on the pressure and temperature of the steam that turbines can use; temperature being the critical factor.

# Chapter 2 Types of Turbines

## 1. How can steam turbines be classified?

IMPULSE and REACTION

IMPULSE - The heat energy is converted to kinetic energy by expanding the steam through stationary nozzles. At the stationary nozzles of all turbines both impulse and reaction, pressure is reduced and velocity is increased. A jet of steam strikes the bucket and converts the kinetic energy of the steam into an impulse force. The impulse force causes the wheel to move producing mechanical energy.

REACTION - In the reaction turbine heat energy is converted to kinetic energy by expanding steam through the stationary nozzles. The rotating wheel has nozzles mounted on it. As steam escapes from the nozzles a reaction force is produced that forces the wheel in the opposite direction. The stationary and moving nozzles of a reaction turbine are blades that look like

a teardrop in cross-section. The middle of the teardrop acts as the convergent part of the nozzle and the thin tails act as the divergent part of the nozzle.

The impulse turbine uses some reaction forces and the reaction turbine uses some impulse forces.

*D.E.S.C. Simple Steam Turbines page 6 & 7*

## 2. How else can steam turbines be classified?

By the number of stages:
(1) single stage
(2) multiple stages

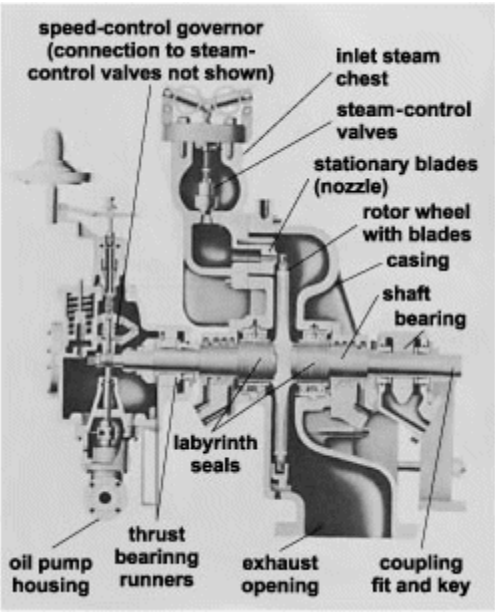



Figure 40. Single Stage Turbine

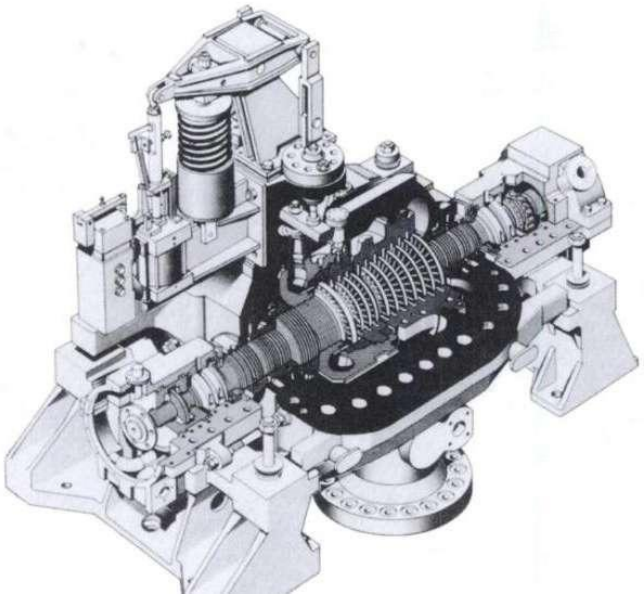


Figure 41. Multiple Stage Turbine

By the direction of steam flow:
(1) axial flow as are most turbines

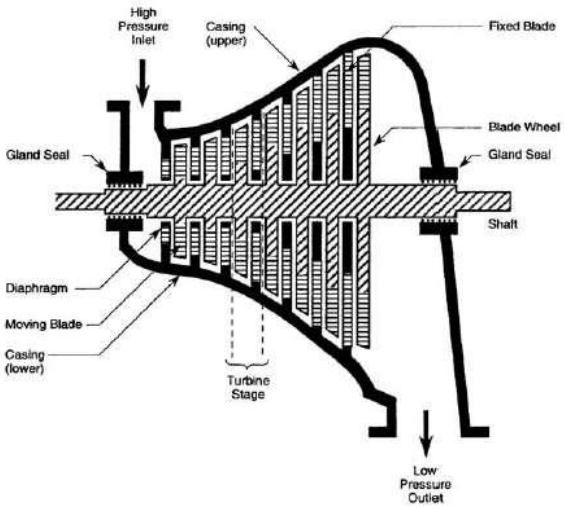



Figure 42. Axial flow turbine

(2) radial flow. This Ljungstrom turbine has steam entering the center and flows outward with two rotors attached

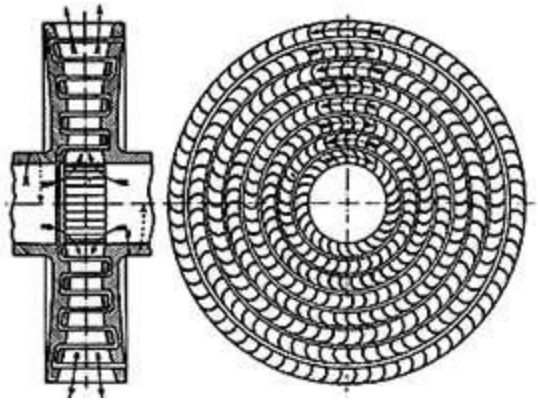


Figure 43. Radial flow turbine

Figure 44. Radial flow Ljungstrom turbine

(3) tangential or helical flow

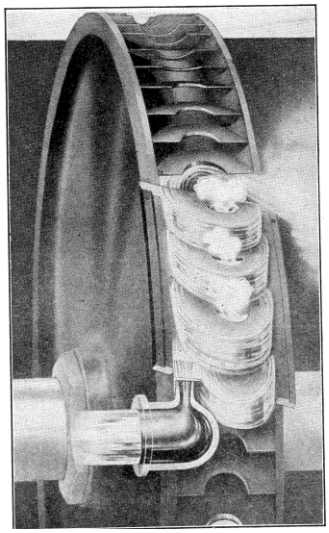


Figure 45. Helical or tangential flow turbine like the Terry and BF Sturtevant. Terry sued Sturtevant for patent infringement and won in March 1915.

By how steam is used:

(1) bleeder

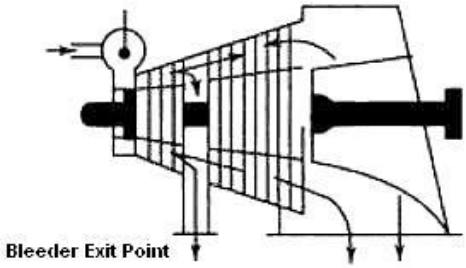



Figure 46. Bleeder turbines do not control the pressure or temperature of the steam from the bleed port

(2) extraction

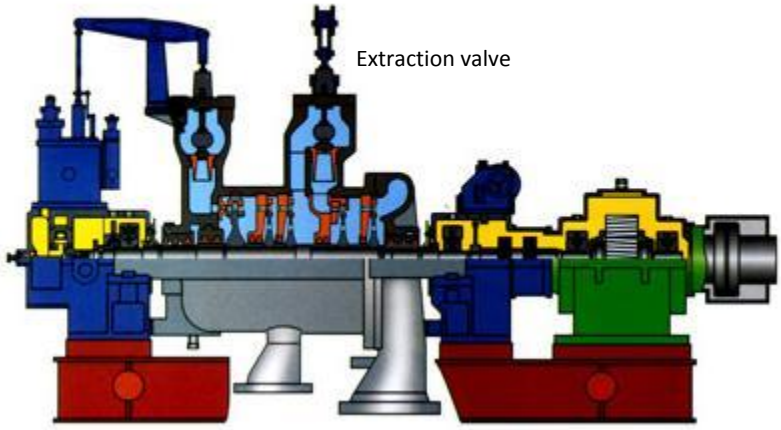



Figure 47. Extraction turbines control the pressure of the steam at the extraction port. This can also be used to control steam temperatures which is useful for industrial processes that require precise temperature limits during manufacture. An example would be the drum that paper pulp runs over to turn the pulp into a finished roll of paper.

By the inlet steam pressure:
(1) high pressure
(2) medium pressure
(3) low pressure

By the exhaust pressure:

(1) condensing

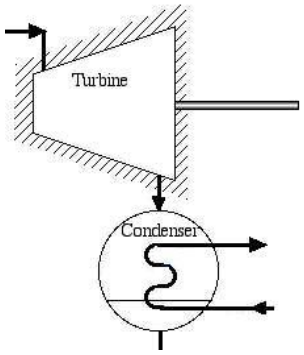



Figure 48. Diagram showing a condenser to increase power and recover condensate for reuse

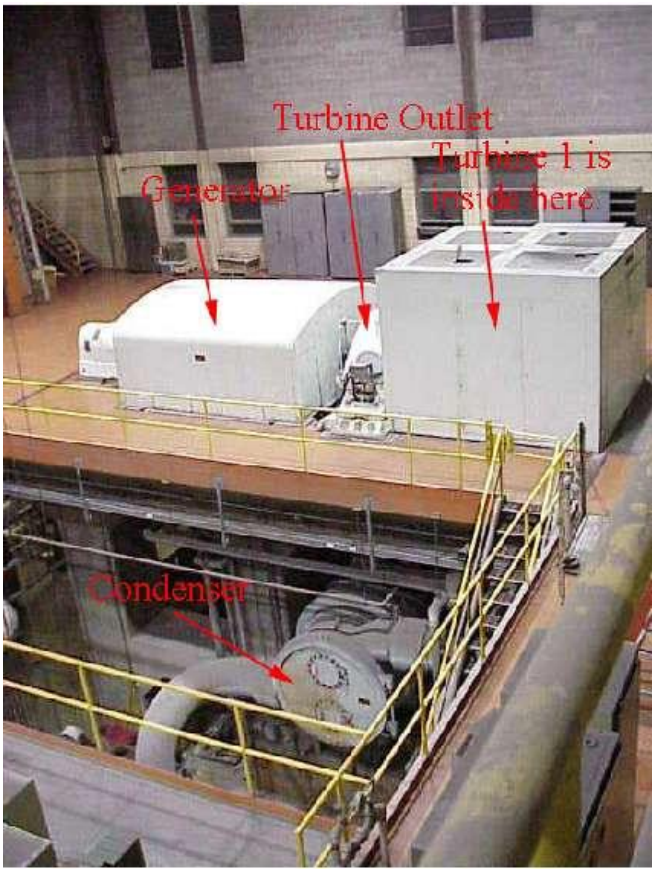



Figure 49. Shows the physical location of the condenser under the turbine

(2) non-condensing

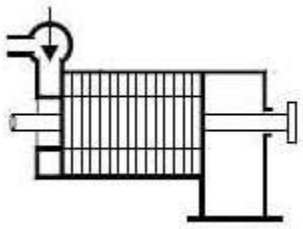


Figure 50. Non-condensing turbines are also known as back pressure turbines because the exhaust at pressures above atmospheric

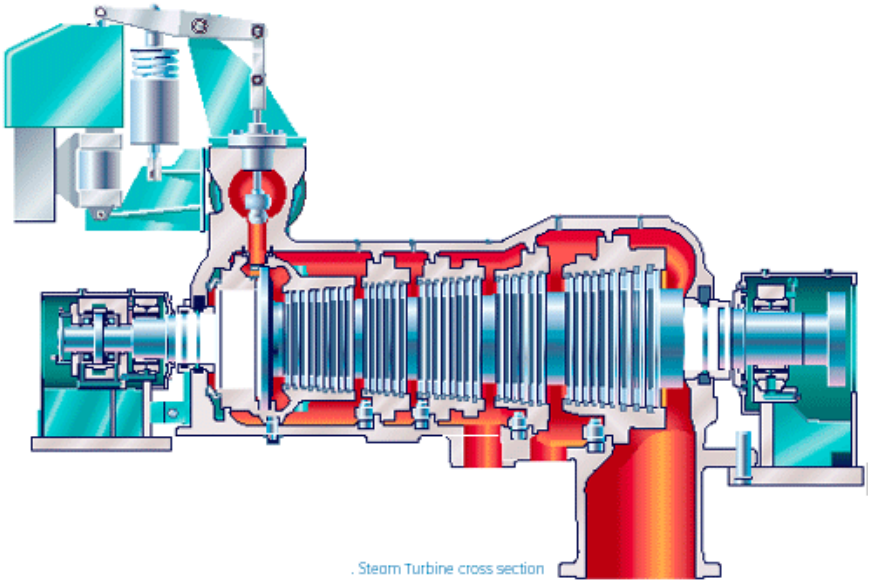



Figure 51. Non-condensing back pressure turbine

By position to other turbines:
(1) Superposed or Topping
(2) Subposed

By number of casings:
(1) Tandem Compound
(2) Cross Compound

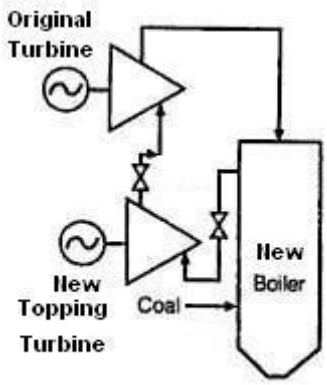



Figure 52. Superposed turbine schematic

## 3. What is a superposed turbine?

When an older lower pressure boiler is replaced with a newer high pressure unit, capital costs can be decreased by reusing the old turbine. A superposed turbine is a high backpressure, non-condensing turbine designed and installed to use its exhaust steam to feed a lower pressure turbine. The exhaust steam of the new turbine has the same pressure as the old boiler and is used to supply the old turbine. This acts as a reducing station for the lower pressure turbine. An example would be a new steam boiler supplying steam at 1200 psig to a high back pressure, non-condensing turbine which exhausts at 300 psig to the lower pressure turbines. The addition of superposed units in older plants has increased the efficiency by as much as 30% in some of these plants. Turbines will normally outlast the boilers that supply them.

*Detroit Edison Steam Course Turbine Operation and Maintenance, page 3.*

## 4. What is a subposed turbine?

Subposed turbines are low pressure condensing turbines using exhaust steam from steam engines or process equipment.

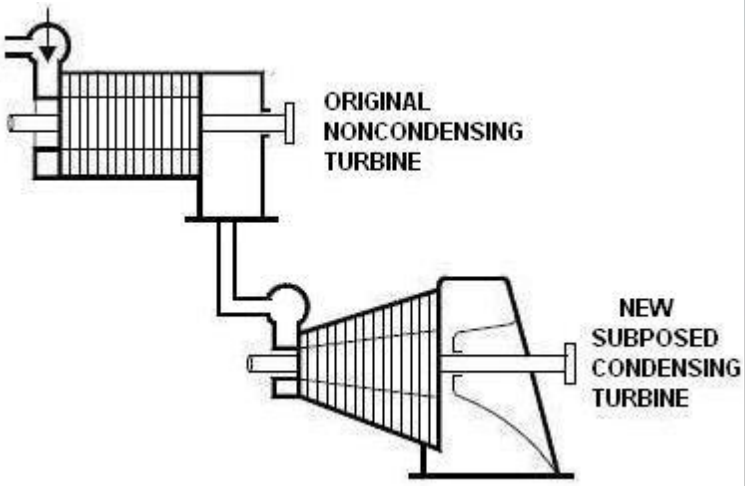



Figure 53. In order to extract more work from an existing non-condensing turbine, a new subposed condensing turbine is added to the exhaust of the original turbine.

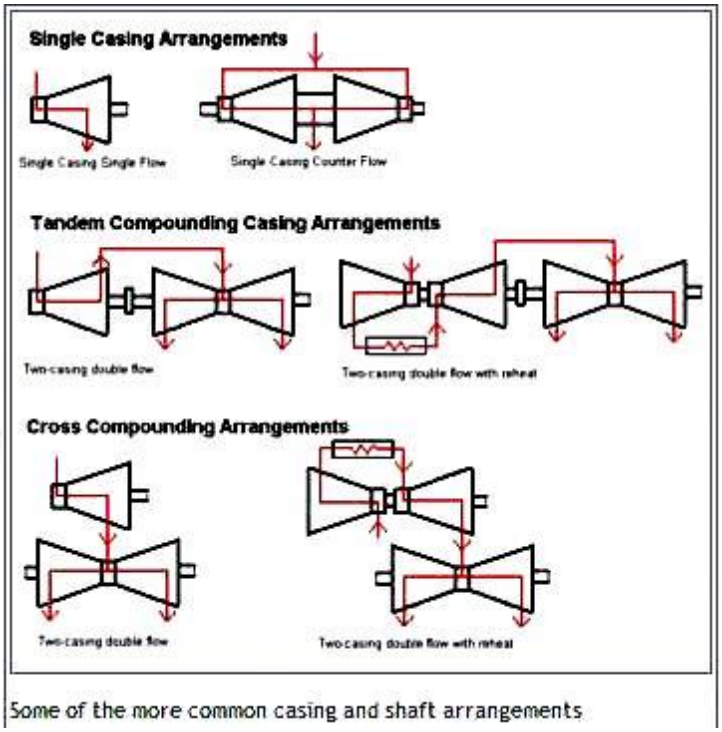

Single Casing Arrangements
Single Casing Single Flow
Single Casing Counter Flow
Tandem Compounding Casing Arrangements
Two-casing double flow
Two-casing double flow with reheat
Cross Compounding Arrangements
Two-casing double flow
Two-casing double flow with reheat
Some of the more common casing and shaft arrangements

Figure 54.

**5. What are the principal types of turbines in regards to steam flow.**

1) Straight condensing

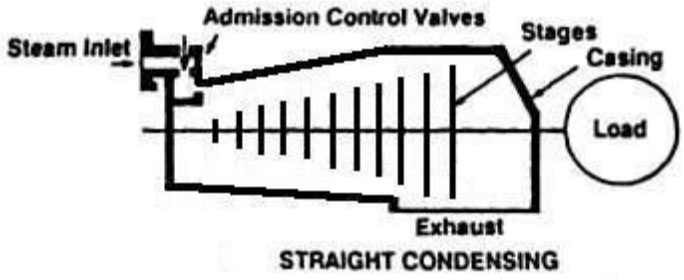



Figure 55.

2) Condensing low pressure
3) Condensing bleeder

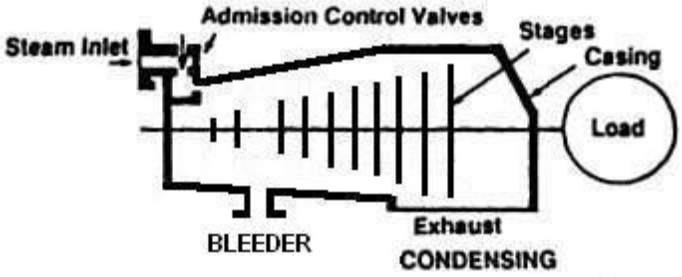



Figure 56.

4) Condensing single automatic extraction

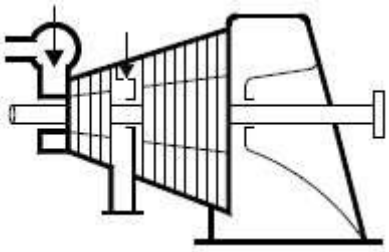


Figure 57. Single automatic extraction condensing

5) Condensing double automatic extraction

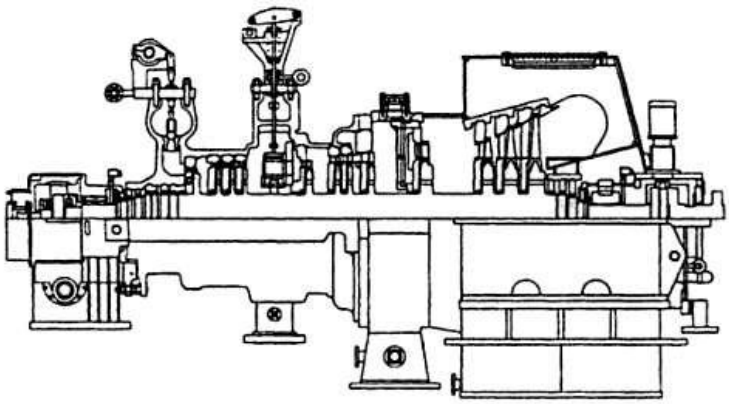


Figure 58.

Double Automatic Extraction Condensing

6) Condensing mixed pressure

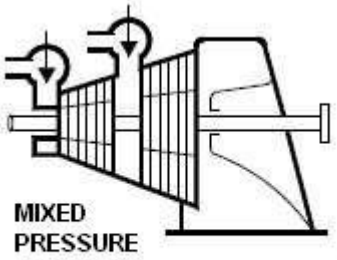



Figure 59.

7) Condensing mixed pressure induction-extraction

A mixed pressure turbine receives steam at two pressures. High pressure steam to the first stage and low pressure steam from another source admitted to an intermediate stage of the turbine to continue its expansion to the turbine exhaust. A mixed pressure turbine has the same general physical layout as extraction turbine. The difference in operation with the low pressure steam flowing into the turbine instead of being extracted from the turbine. A mixed pressure turbine if properly valved can also serve as an automatic extraction turbine.

*D.E.S.C. Modern Turbines page 11*

*S&V page 16*

Mixed-pressure turbines take steam from high pressure or low pressure sources or both to generate shaft power. A mixed-pressure turbine can take in high pressure steam from a boiler and also low pressure steam at an intermediate stage. Automatic-extraction units may also act as mixed-pressure turbines.

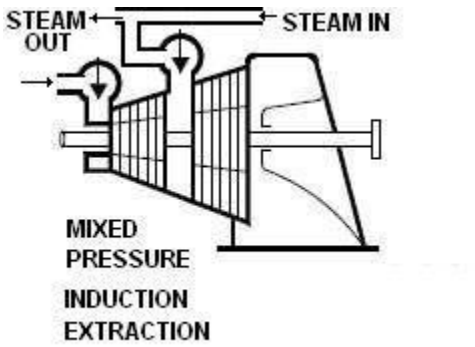



Figure 60. Depending on whether there is an excess of steam or a need for steam for a process, an induction-extraction turbine can move steam in either direction

8) Non-condensing
9) Non-condensing bleeder

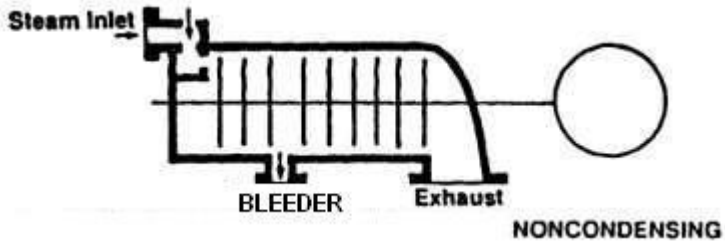



Figure 61.

10) Non-condensing single extraction

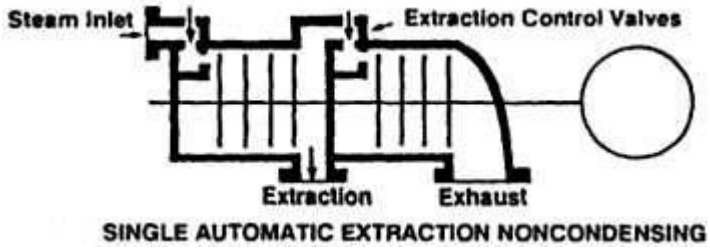



Figure 62.

11) Non-condensing double extraction

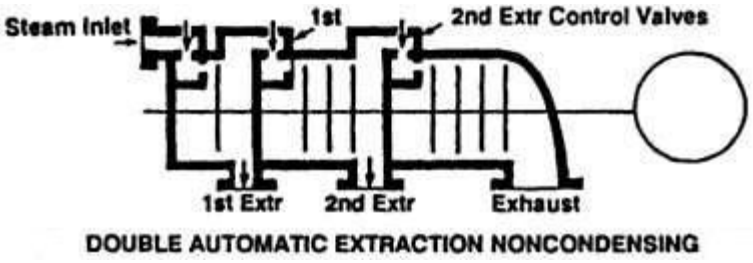



Figure 63.

**6. How may these classes be further sorted according to steam flow in the turbine:**

1) Straightflow
2) Non-automatic-extraction
3) Automatic-extraction
4) Reheat

1) Straightflow uses full-throttle steam from nozzles to exhaust. Steam enters one end of the turbine and passes across the blades approximately parallel to the axis of rotation, expanding as it passes through the turbine and is discharged to the atmosphere, another turbine, or a condenser

2) Nonautomatic-extraction turbines bleed steam at as many as nine different stages. Pressure of extracted steam at each stage varies with the turbine shaft load. But pressure variations like this can seldom be tolerated for process work. So these units usually work as generator drives; extracted steam is used for feedwater heating. Non-automatic turbines are also called bleeder turbines.

3) An automatic-extraction unit bleeds off part of the main steam flow at one, two, or three points. Valved partitions between selected turbine stages control extracted steam pressure at the desired level. Portions of main steam flow are extracted for process steam at various stages in turbine. When the extracted steam flow through the unit does not produce enough shaft horsepower to meet the demand, more steam flows through to the exhaust. In the case of grid valves this means they open more to allow more steam to pass through to the later stages of the turbine. These turbines are put between steam-supply headers and process-steam headers. Automatic governing systems correlate steam flows, pressures, shaft speed and shaft output. An automatic-extraction turbine is a form of bleeder turbine with bleed pressure remaining constant at all loads through the use of single-seat valves or grid valves.

4) In reheat, after the steam expands through the high pressure turbine, main steam flow exhausts from the unit at an intermediate stage. It is resuperheated, usually in the boiler furnace before being sent to the intermediate or low pressure turbine for further expansion before exhausting to the condenser. Reheating increases turbine efficiency and overall plant efficiency, decreases moisture in the low pressure end of the turbine and reduces the piping size of main steam turbine due to the decrease in steam consumption. Some units have two stages of reheating.

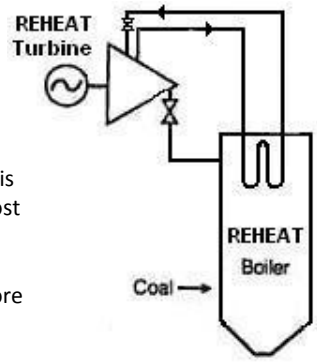



Figure 64. Steam from the boiler is sent to the turbine. After it has lost some heat and before starts to form moisture, it is sent to the reheater to increase its heat before returning to the turbine.

## 7. Explain the different types of turbine arrangements and explain the reasons for using the different types.

Basic types of turbines can be divided into two main classes: condensing units exhausting steam at less than atmospheric pressure, noncondensing units exhausting at higher than atmospheric.

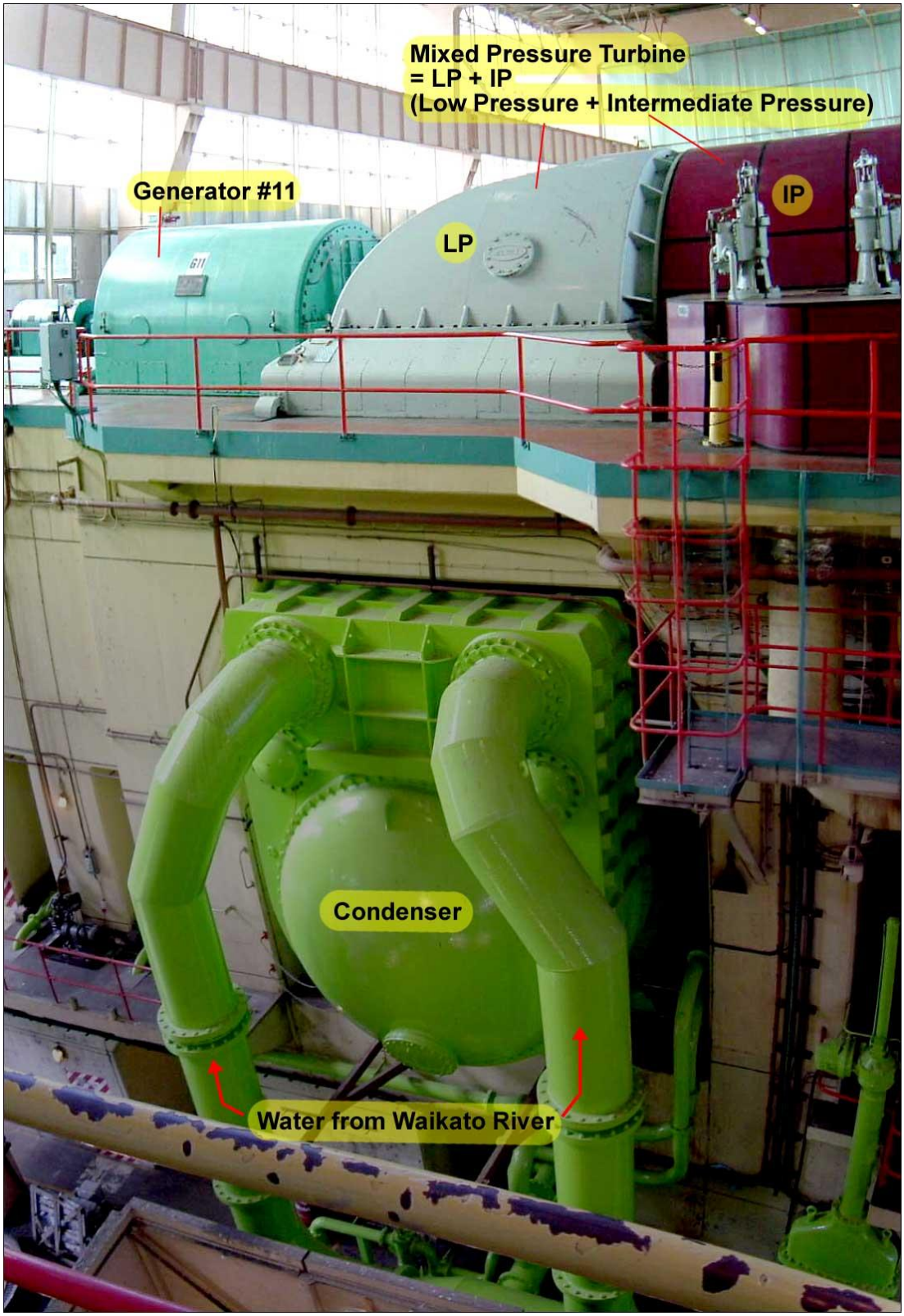



Figure 65. Mixed pressure turbine with condenser

## 8. Describe other type of turbine arrangements

1.) Electrical Generating

2.) Mechanical

Generator-drive turbines often combine condensing, reheating and nonautomatic extraction.

Mechanical-drive turbines are designed to meet varied needs of industry for prime movers to drive fans, pumps, compressors and other machines. This service generally calls for small noncondensing units with exhaust steam used for heating.

Figure 66. Electrical Generating Turbine

Figure 67. Steam Turbine Driven Boiler Feed Pump

### 9. What are some of the advantages of mechanical drive turbines?

Advantages are:

1) easily controlled variable speed operation

2) ability to start quickly and without electrical power

3) freedom from spark hazard

4) suitability for damp or otherwise adverse conditions.

### 10. What are mechanical drive turbines used for?

compressors, pumps, fans and blowers, centrifuges, coal mill drivers

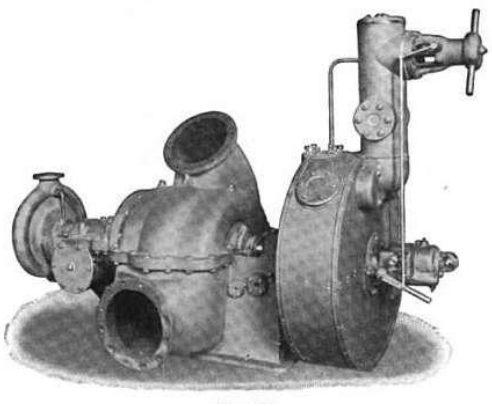


Figure 68. Mechanical Turbine driving a fan

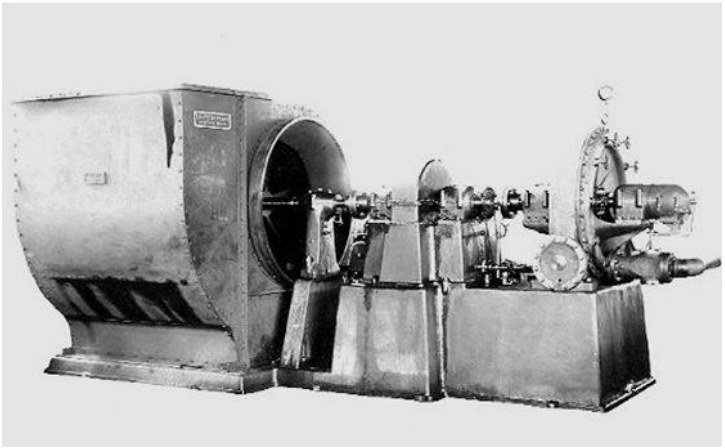


Figure 69. Sturtevant turbine driving a blower

### 11. At what speed do mechanical turbines revolve?

1500 to 20,000 rpm.

### 12. Are mechanical drive turbines usually condensing or non-condensing?

usually non-condensing

### 13. What is the pressure drop across a mechanical turbine?

150 psi inlet to 5 psi outlet in small to medium sized heating plants

### 14. What type of blading do mechanical turbines usually have?

impulse blading

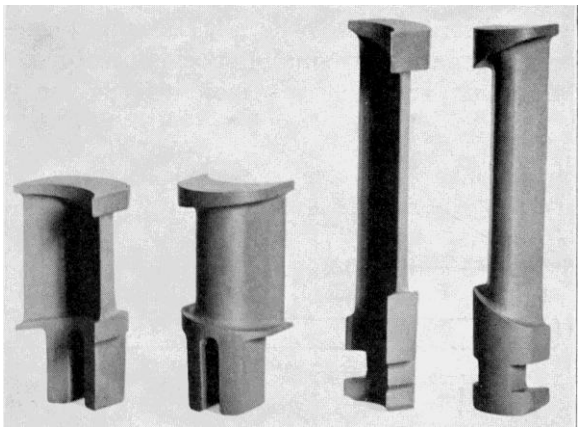


Figure 70. Impulse turbine buckets with tips to form a shroud band

## 15. What is a radial-flow turbine?

There are two types of turbines known as radial flow turbines and one should not be confused with one another.

In the Ljungstrom turbine. Steam enters the center and flows outward through two sets of moving blades each moving in the opposite direction. In electrical generation, a generator is placed on the end of each moving shaft.

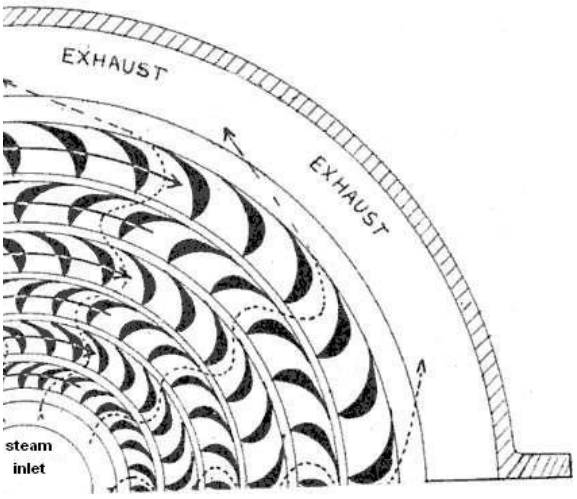



Figure 71. Ljungstrom diagram

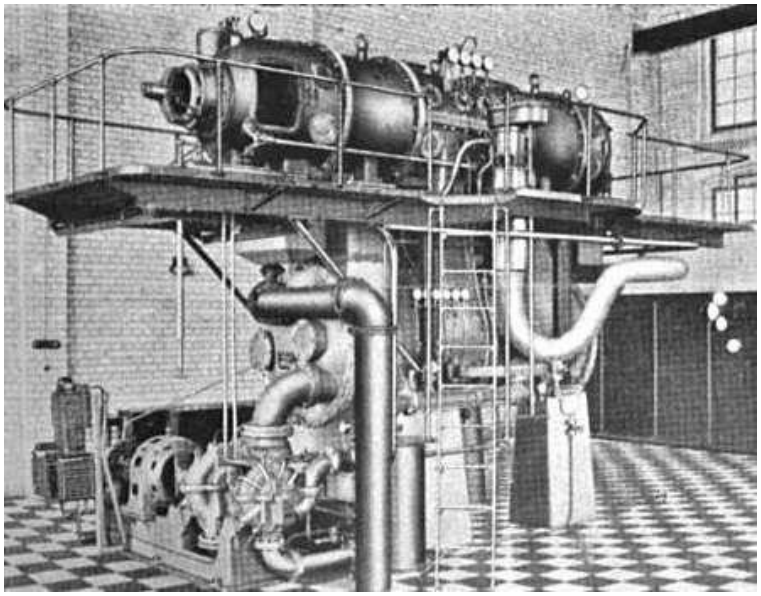


Figure 72. Ljungstrom turbine with generators at both ends

Examples of the other style of radial flow turbines are the Terry Turbines, Sturtevant, and Dresser Rand which took over the Terry Turbine company.

They are small mechanical drive turbines with a rugged single wheel that uses steam in a corkscrew fashion through reversing buckets to achieve velocity compounding.

*S&V pages 41, 42*

Figure 73. Terry turbine wheel

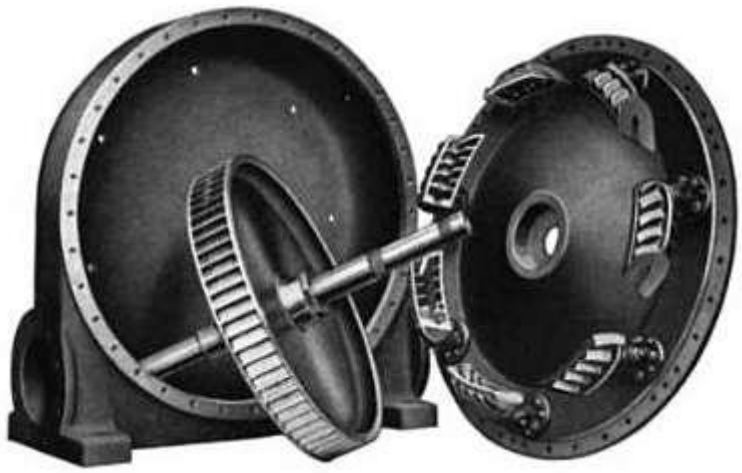


Figure 74. Sturtevant turbine

## 16. Is a Terry turbine velocity or pressure compounded?

The Terry turbine is of the radial re-entry type and is velocity compounded. It is used for driving fans and pumps. In this type of impulse turbine nozzles direct a high velocity jet of steam tangentially from the side into semi-circular buckets. Impulse of the jet strikes and drives the blades. The blades or buckets direct the steam into a circular motion to the reversing buckets where it is redirected to the wheel again. The reversing buckets are mounted to the casing around the periphery of the wheel. This turbine is good at low speeds and is not affected by wet steam as much as other designs of velocity compounded turbines. Usually RPM runs from 5,000 to 12,000 R.P.M. Axial thrust is not a problem with this type as most thrust is in a radial direction.

*S&V page 193*

## 17. What type of turbine is a re-entry turbine?

In the re-entry type the direction of flow of steam jet is reversed and is made to strike the same set of moving blades or buckets two or more times.

Radial re-entry turbines are velocity compounding type.

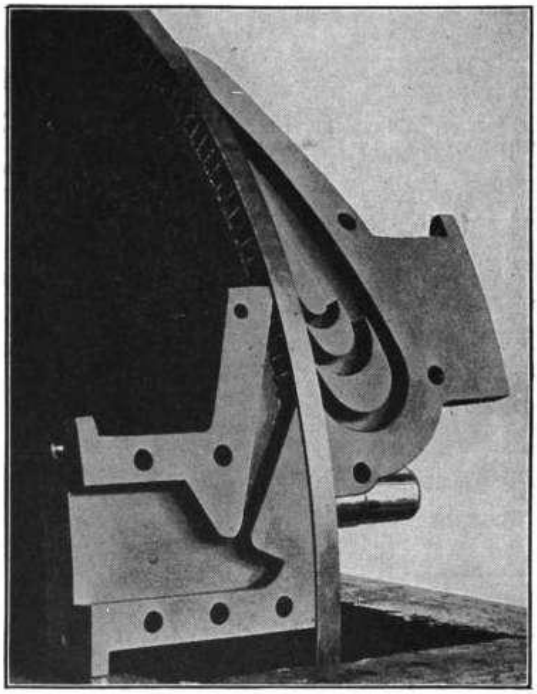
*S&V page 193*

*Croft Steam Turbines page 45*

## 18. Are all re-entry type turbines the radial re-entry type?

No. The nozzles for these designs are commonly part of a reversing chamber assembly, which redirects the steam back through the blades. In the radial re-entry type turbine the fact that the steam is redirected through the same set of blades is due to the stationary blades in the casing causing a helical action on the steam. In the axial re-entry type of turbine the steam is passed through the moving blades, collected and redirected back through the moving blades in a zig-zagging motion.

*S&V pages 41, 42*



Construction of Nozzle and Reversing Chamber of Westinghouse Re-Entry Type Impulse Turbine
*Courtesy of Westinghouse Machine Company, East Pittsburgh, Pennsylvania*

Figure 75. The axial reentry turbine achieves velocity compounding by redirecting the steam through the same turbine wheel

## 19. What are two types of clearance in a turbine?

Radial - clearance at the tips of the rotor and casing.

Axial - the fore-and-aft clearance, at the sides of the rotor and the casing.

## 20. What is a double flow turbine?

Steam enters at the center of the turbine and divides, flowing axially in opposite directions through separate sets of blades. This opposed steam flow tends to equalize the end thrust of the rotor. A double flow turbine is generally used as the low pressure unit where higher power is desired. Other than tending to equalize the thrust of the rotor, double flow principles are used to keep the size of the turbine within reasonable limits. After passing through a high pressure or intermediate pressure casing, the volume of steam becomes too great to be passed through a single flow low pressure casing of reasonable size.

*D.E.S.C. Turbine Operation and Maintenance. page 21.*

Special types of turbines include the double-flow-exhaust, sometimes used for mechanical drive units. This design permits high shaft speeds and low backpressures where steam volume grows enormously and calls for very large passages between last stage blades.

Figure 76. Steam enters the center of this double flow turbine and flows toward the exhaust in either direction. This keeps the last stage blades shorter and equalizes the thrust.

## 21. What are straight non-condensing turbines?

Straight-noncondensing turbines work over a wide range of throttle and exhaust conditions. When extra shaft power and steam are needed, an additional high pressure turbine can be added. Supplied with steam by a new high pressure boiler, superposed units exhaust at high backpressure into existing main steam supply lines.

## 22. What are compound turbines?

Compound turbines are units in which the steam passes in sequence through two or more separate casings.

There may be a high and a low pressure turbine; or high intermediate, and low; or high. first intermediate, second intermediate, and low pressure turbine.

The advantages of compounding turbines are:

1.) smaller structure for each casing

2.) smaller temperature range in each casing,

3.) little or no design limitation regarding efficiency

4.) provides possibility of reheat or moisture removal after partial expansion.

Tandem-compound and cross-compound turbines are the arrangements of choice when it comes to electrical power generation for The Detroit Edison Company. Both arrangements will allow for reheat cycles which are necessary to obtain the most efficient use of steam.

Tandem compound is when the cylinders are in line. Tandem-compound designs work on a single shaft with the turbine containing a high, intermediate, and low pressure section. The steam is sometimes sent back to the boiler for reheating between the high pressure stage and the intermediate stage where it recovers some heat from the products of combustion which would have otherwise gone up the stack. The steam then goes through the intermediate stage and from there to the low pressure stage where it is introduced into the turbine and flows in opposite directions. This design allows the turbine to maintain a minimum length and also a minimum blade diameter in the final passes.

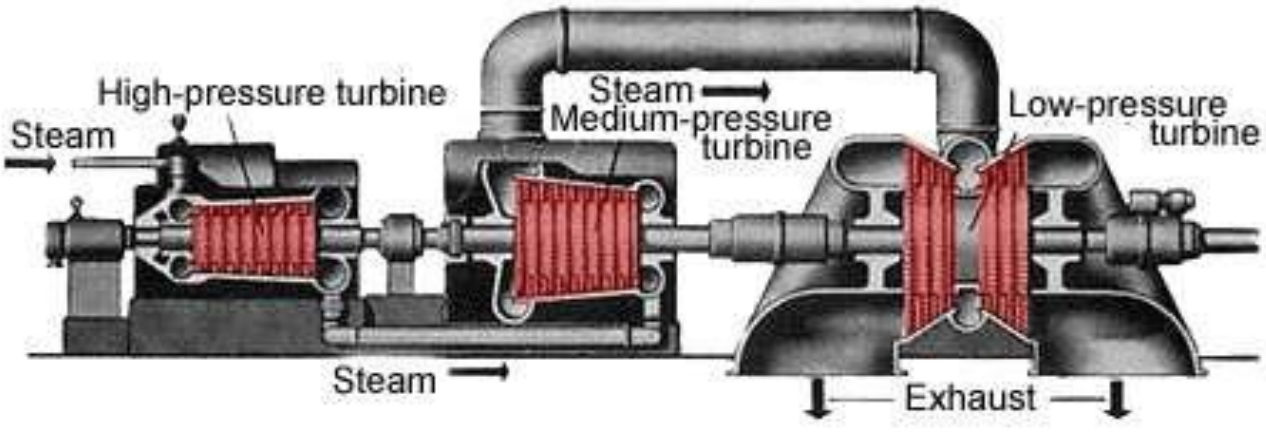



Figure 77. Tandem Compound Turbine

Cross-compound is when cylinders are parallel to each other. Cross-compound turbines operate similarly to the tandem-compound with the exception of the number of shafts, two and sometimes three. This also permits for a minimum shaft length, but more importantly allows the low pressure end to rotate at a slower speed.

*D.E.S.C. Modern Turbines page 4,D.E.S.C. Turbine Operation and Maintenance. page 21,S&V Turbines page 18,*

*.Power, Steam Turbines, reprint June 1962, pageS-14 thru S-16.*

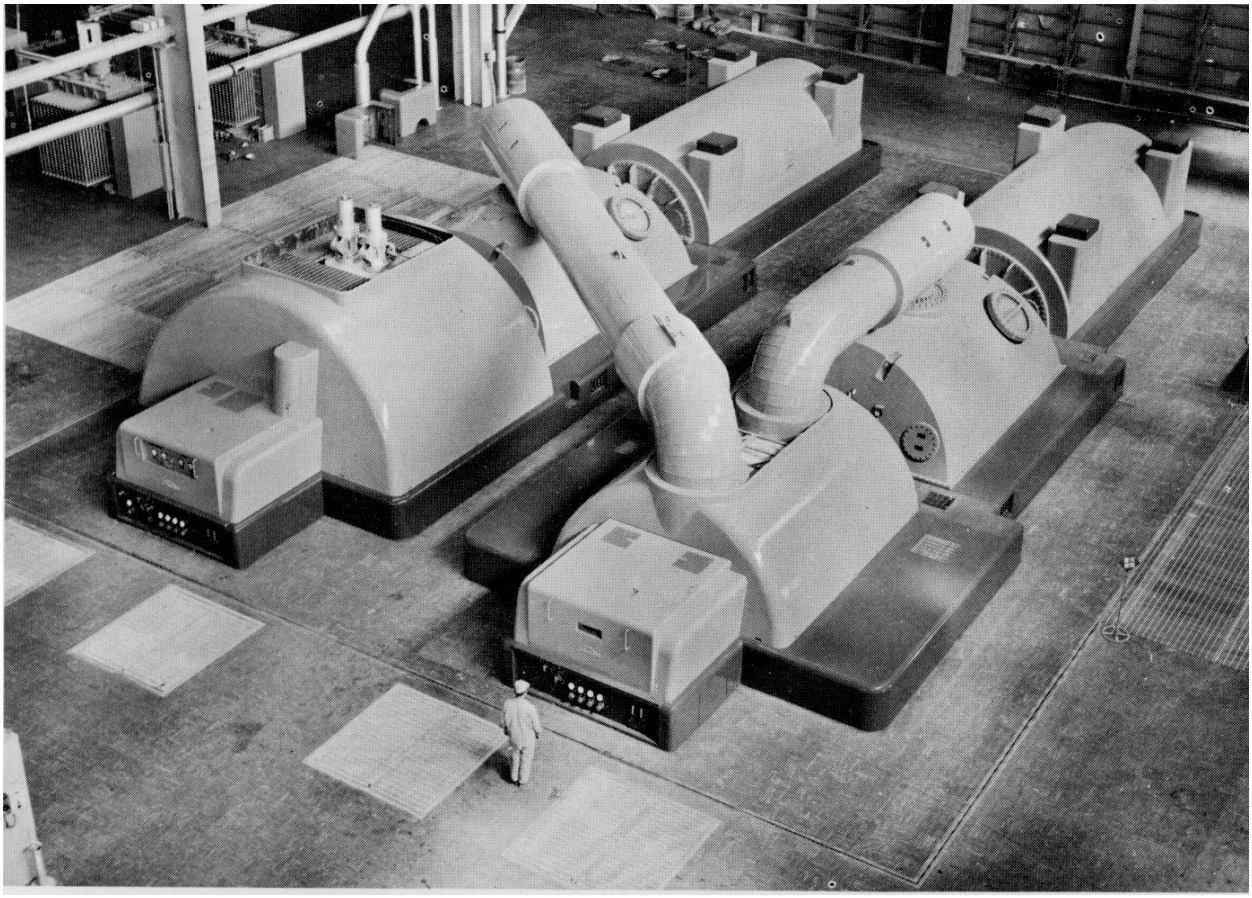


Figure 78. Cross Compound Turbine Notice the size of the Turbine Operator

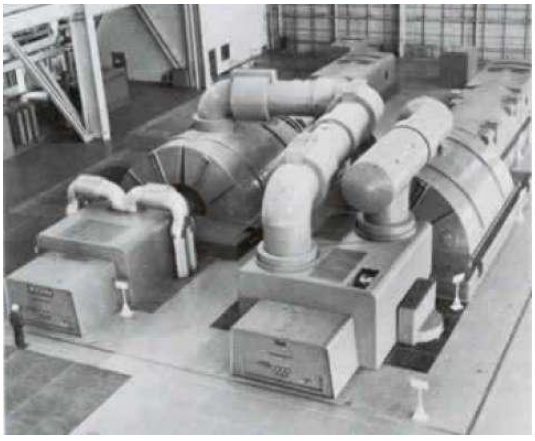


Figure 79. Can you spot the operator on this cross-compound turbine?

Figure 80. Cross compound turbine located outside. This is normally found in desert areas

## 23. How could you tell a condensing turbine from a non-condensing turbine just by looking?

A condensing turbine has a cone shaped outer shell due to the increase in the size of the blades as the pressure gets lower while a non-condensing turbine has a cylindrical shaped outer shell.

Does the unit have a condenser under it or does it have an exhaust pipe. Look to see what pressure the last stage is under, non-condensing units exhaust at a pressure above atmospheric and the steam is used elsewhere for heating or process work. Also look for a vacuum breaker or atmospheric relief valve. Sometimes called a blowout disc. These are found on condensing units.

*Tour Guide at Trenton Edison*

*D.E.S.C. Turbine Operation page 32*

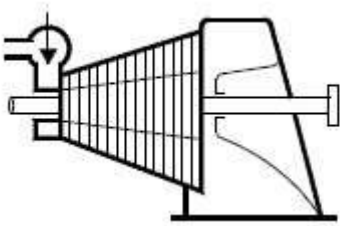


Figure 81. Condensing Turbine

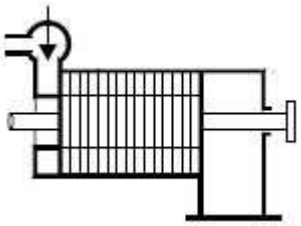


Figure 82. Non-Condensing Turbine

## 24. Why do blades get larger on condensing turbine rotors and stay the same on non-condensing turbine rotors?

The lower pressure of condensing turbines expands the steam more than non-condensing turbines. In order for each stage of turbine blading to do equal work on the rotor with the reduced pressure and increased volume of steam it receives, the lower pressure blading must get bigger.

Figure 83. The larger turbine blading on the low pressure end denotes a condensing turbine

## 25. Why are noncondensing turbines used?

Non-condensing turbines are used where a relatively large process demand exists at a single, low temperature.

Most boiler feed pump turbines in small boiler rooms are of the single stage impulse, single stage reaction, or the impulse reaction type?

Because impulse wheels operate satisfactorily with partial steam admission and for a given speed take a large pressure drop with good efficiency, virtually all mechanical-drive turbines are of impulse design, frequently velocity-compounded. Velocity compounded turbines have one pressure drop after the stationary nozzle and are therefore considered to be single stage impulse turbines.

*S&V page 31*

# Turbine Construction

**26. Name the parts of a turbine.**

Parts of a turbine include the:

Chapter 3. Rotor, shaft or spindle

Chapter 4. Shell or casing and studs

Chapter 5. Blades or buckets

Chapter 6. Lacing wire

Chapter 7. Diaphragms

Chapter 8. Nozzles

Chapter 9. Main steam admission valves

Chapter 10. Governor and overspeed trip

Chapter 11. Lubrication system

Chapter 12. Main bearings

Chapter 13. Thrust bearings

Chapter 14. Dummy piston or balance piston

Chapter 15. Seals and glands

Chapter 16. Turning gears

Chapter 17. Reduction gears

Chapter 18. Couplings

Chapter 19. Feedwater heaters

Chapter 20. Extraction trips

Chapter 21. Condensers and air ejectors

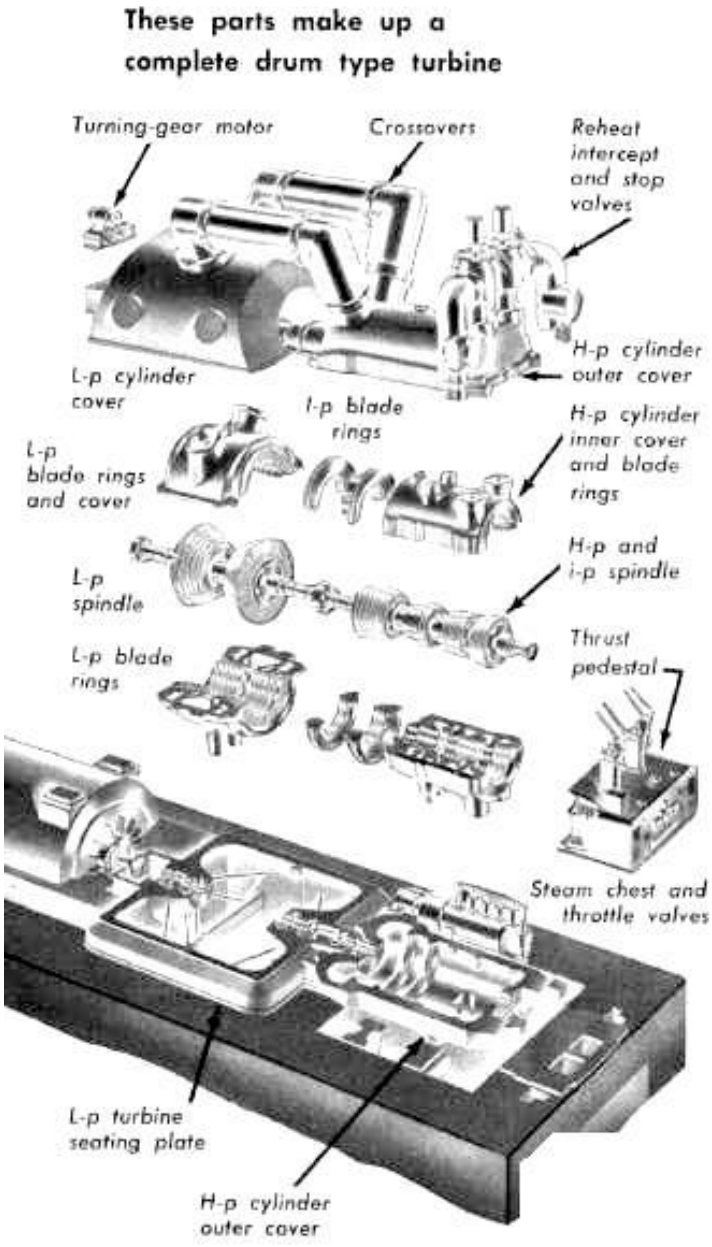



Figure 84. Parts of the turbine

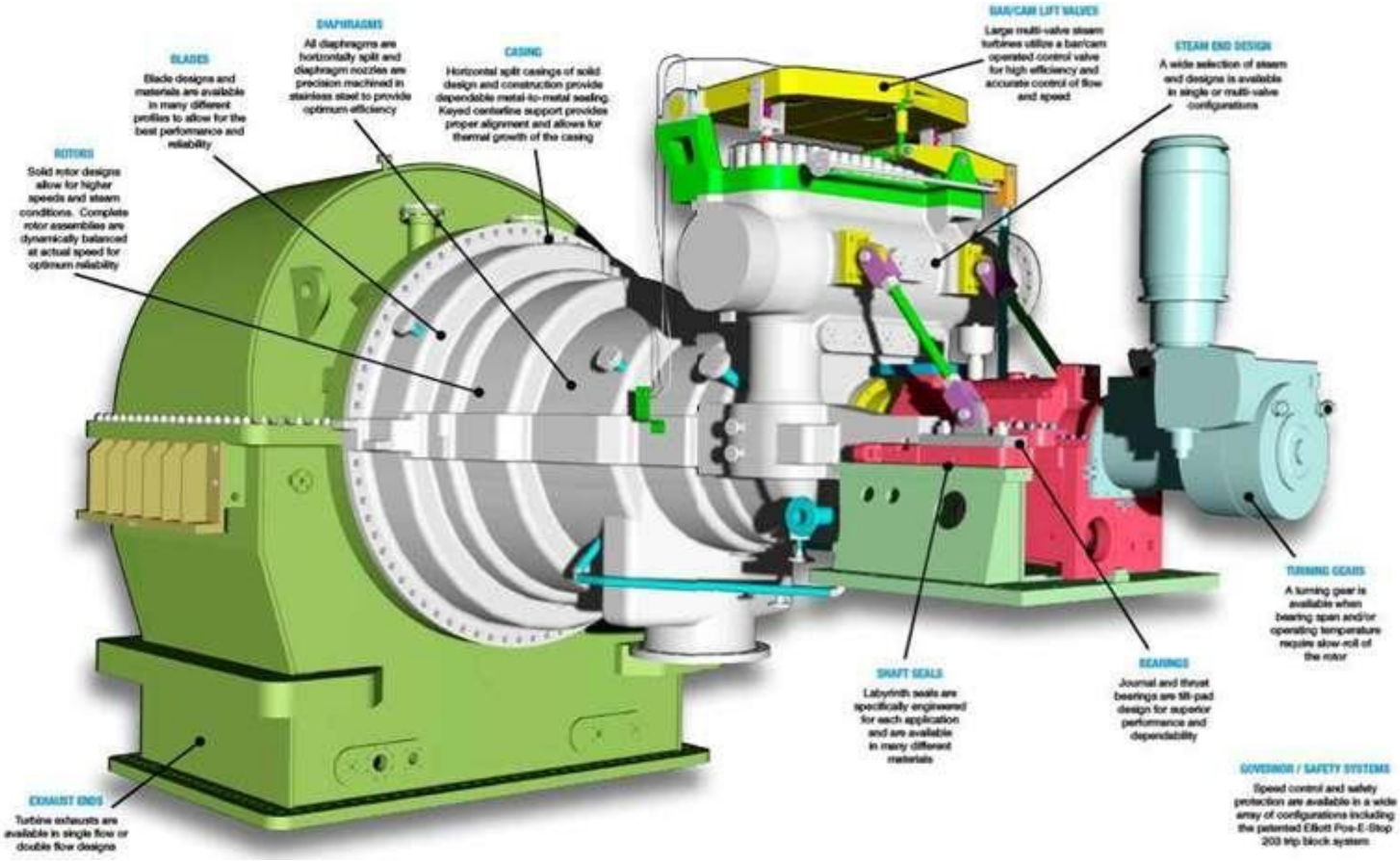

BAR/CAM LIFT VALVES
Large multi-valve steam turbines utilize a bar/cam operated control valve for high efficiency and accurate control of flow and speed
STEAM END DESIGN
A wide selection of steam end designs is available in single or multi-valve configurations
DIAPHRAGMS
All diaphragms are horizontally split and diaphragm nozzles are precision machined in stainless steel to provide optimum efficiency
CASING
Horizontal split casings of solid design and construction provide dependable metal-to-metal sealing. Keyed centerline support provides proper alignment and allows for thermal growth of the casing
BLADES
Blade designs and materials are available in many different profiles to allow for the best performance and reliability
ROTORS
Solid rotor designs allow for higher speeds and steam conditions. Complete rotor assemblies are dynamically balanced at actual speed for optimum reliability
TURNING GEARS
A turning gear is available when bearing span and/or operating temperature require slow-roll of the rotor
SHAFT SEALS
Labyrinth seals are specifically engineered for each application and are available in many different materials
BEARINGS
Journal and thrust bearings are tilt-pad design for superior performance and dependability
GOVERNOR / SAFETY SYSTEMS
Speed control and safety protection are available in a wide array of configurations including the patented Elliott Pos-E-Stop 203 trip block system
EXHAUST ENDS
Turbine exhausts are available in single flow or double flow designs

Figure 85. Parts of a turbine

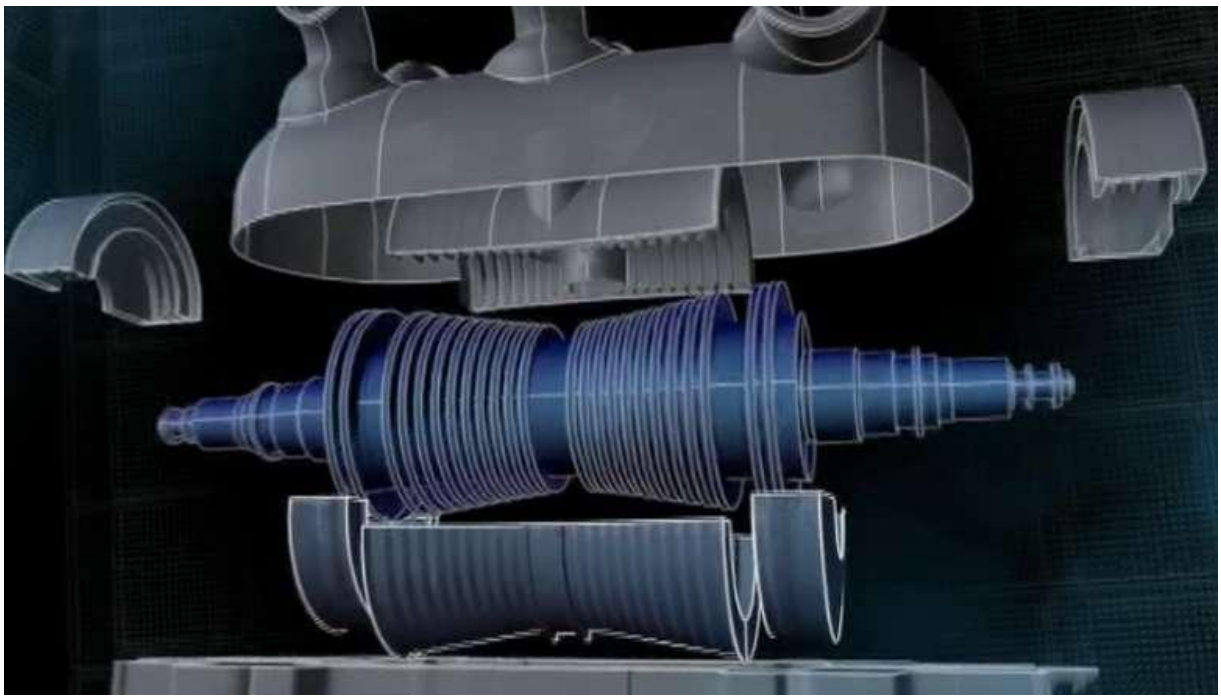


Figure 86. Phantom view inside the turbine

# Chapter 3 Rotors

## 1. What are the three types of rotors?

A.) Solid Forging
B.) Built Up
C.) Hollow Shaft

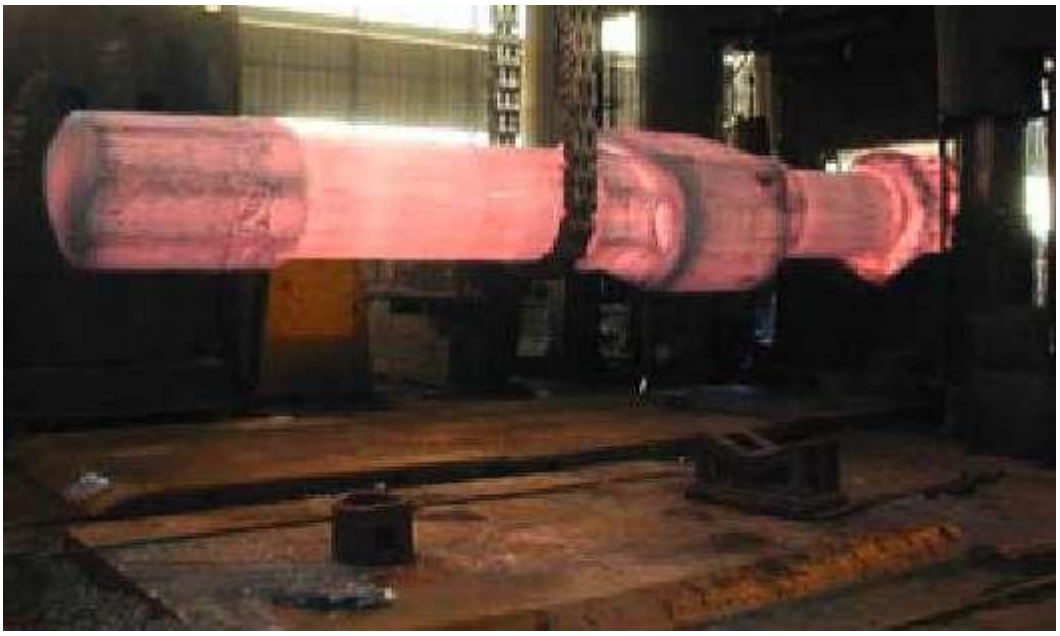


Figure 87. Solid rotor forging

## 2. How are rotors made?

Rotors are made from selected billets which are forged, heat-treated, and machined to proper size. They are commonly made of carbon and nickel steel for temperatures up to 750 F. Above 750 F. nickel-chromemoly steel is used. Solid rotors are machined from steel forgings. These types are used with high speed machines.

Solid rotors are no longer produced in the United States.

*Ted Antil. Chief Engineer. IPMC paper Co*

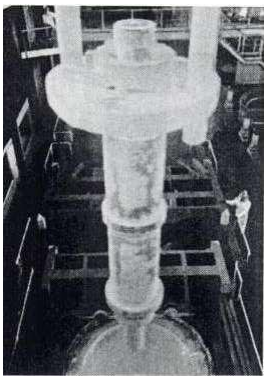


Figure 88. Solid rotor forging with dummy piston on top

Figure 89. Solid rotor forging

Figure 90. Solid rotor during forging

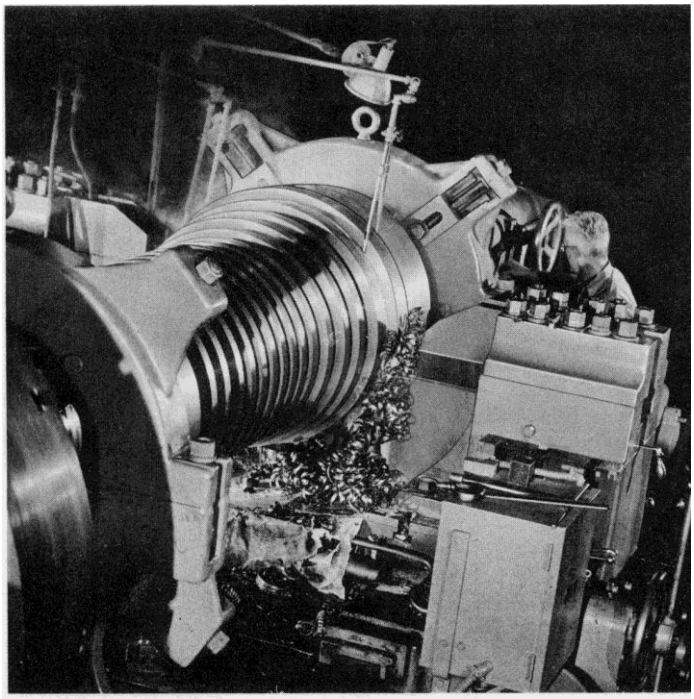
Figure 91. Solid rotor before preliminary machining showing the extreme size of the rotor

Figure 92. Solid rotors before preliminary machining

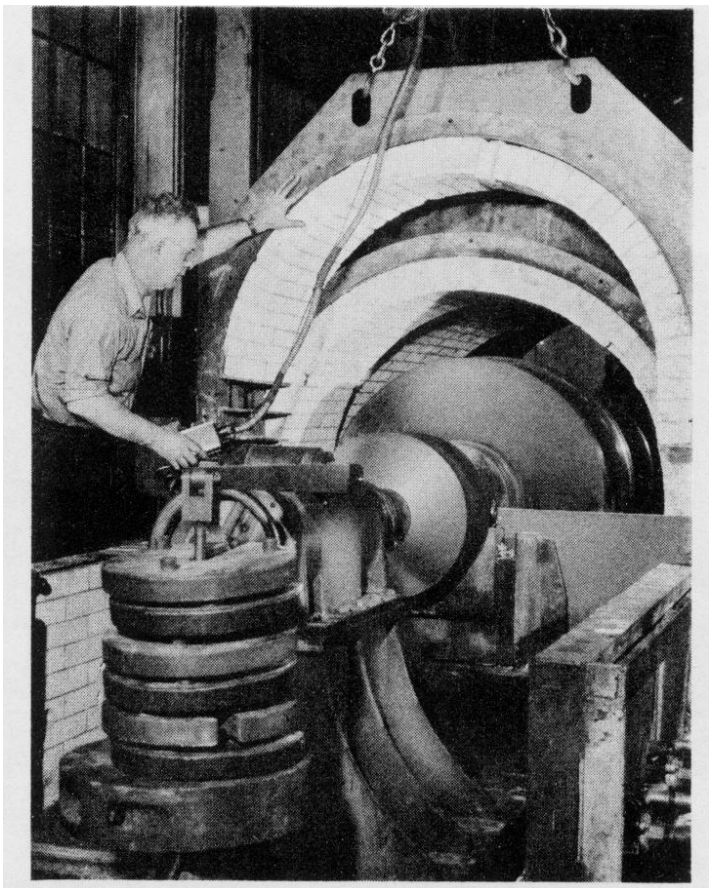
Figure 93. Solid rotor after preliminary machining

Figure 94. Solid rotor after preliminary machining

Figure 95. Solid rotor after more machining



Solid rotor forging undergoing a rough machining. Figure 96.



After final machining all turbine rotors are subjected to a heat stabilization treatment to remove any stresses set up during machining and determine that the rotor will run true when in operation.

Figure 99.

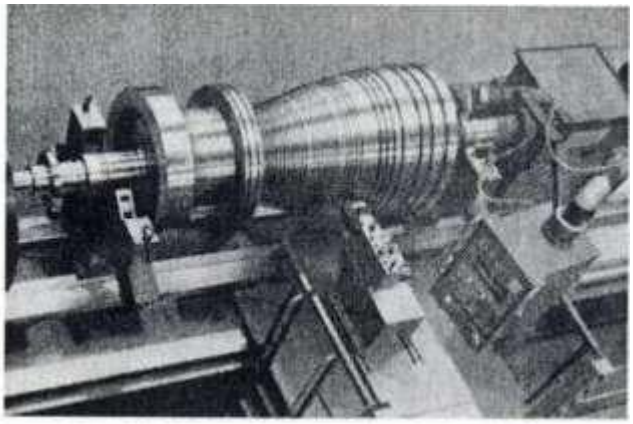
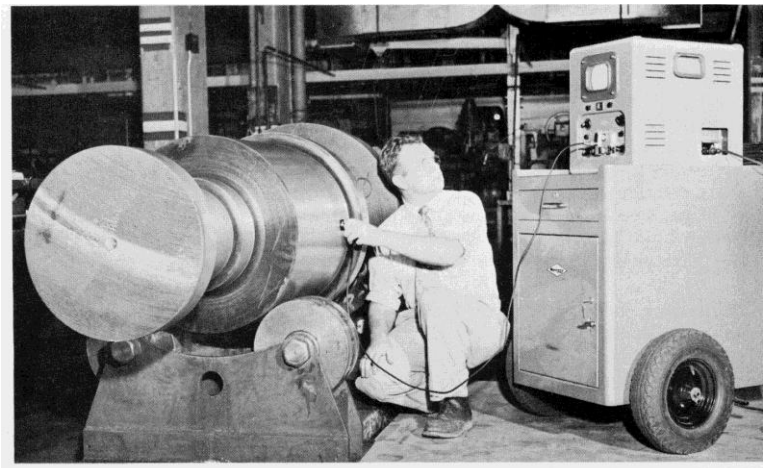


Figure 97. Machining a solid rotor



The accepted rotor forging is given an ultrasonic test to detect small flaws which might be present deep within the forging.

Figure 98. Testing the solid forging for defects

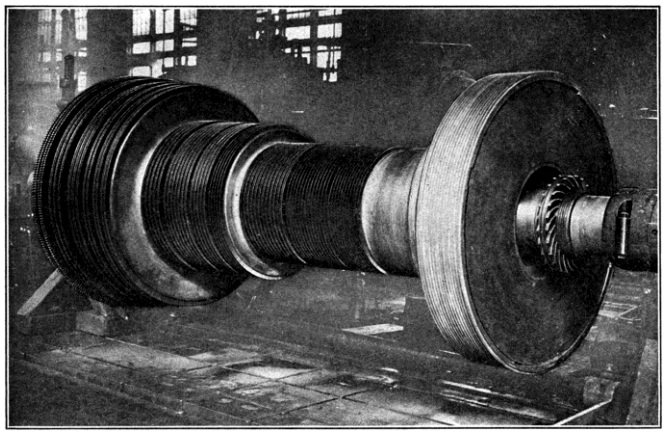


Figure 100. Machined solid rotor with balance piston

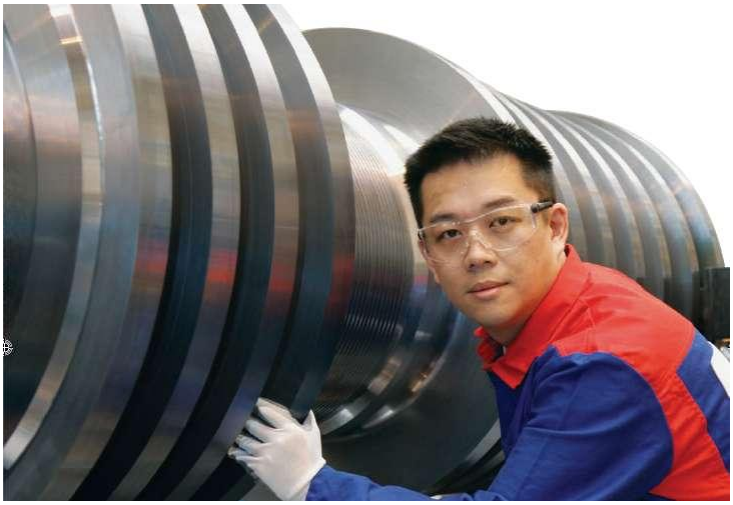


Figure 101. Machined solid rotor before machining the steeples

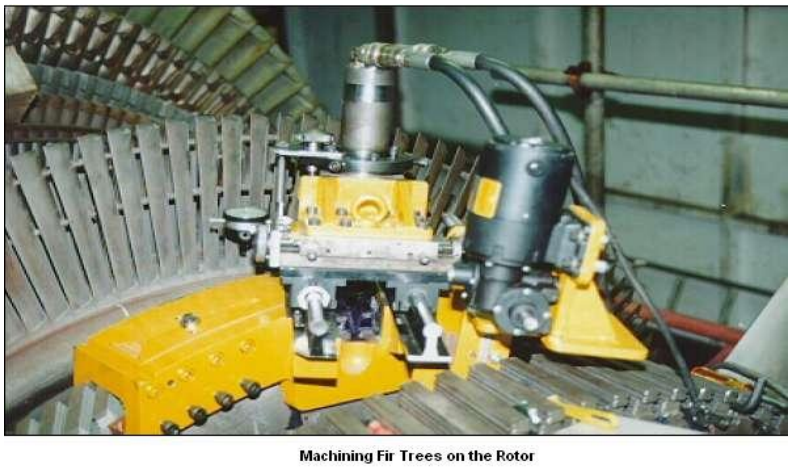



Figure 102. The machine used to cut the steeples on the rotor

Figure 103. Turbine rotor showing the cutting bit used to machine the steeples on the rotor to hold the blades

Figure 104. Installing blades on steeples

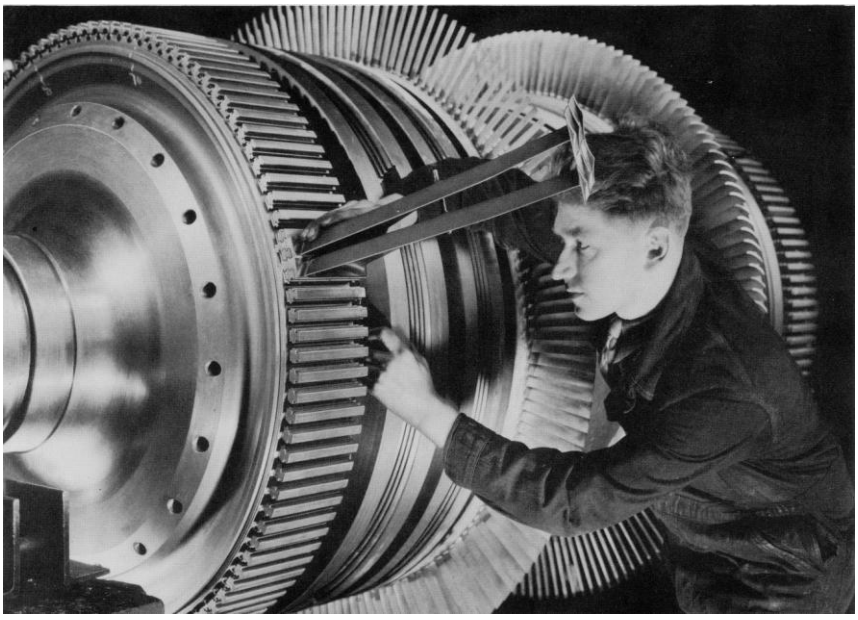


Figure 105. Installing blades on the steeples

## 3. What is a built up rotor?

There are two (2) types of built-up rotors. In one the wheels are pressed on and shrunk or keyed on the shaft. In the second type the wheels are pressed or shrunk on collars of different diameters cut on the hollow shaft. This type is found on low speed units.

*D.E.S.C. Turbines page 19, Croft Turbines page 56*

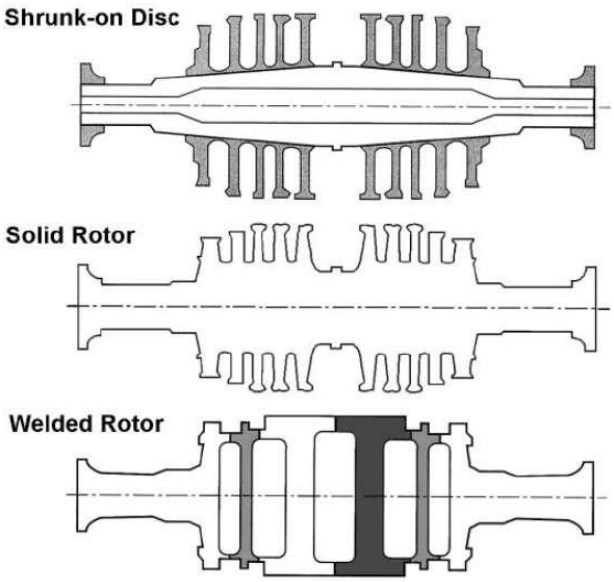



Figure 106. The three types of steam turbine rotors

Welded drum-type LP rotor

Figure 107.

Figure 108. Welded rotor pieces

Steam turbine rotor manufacturing

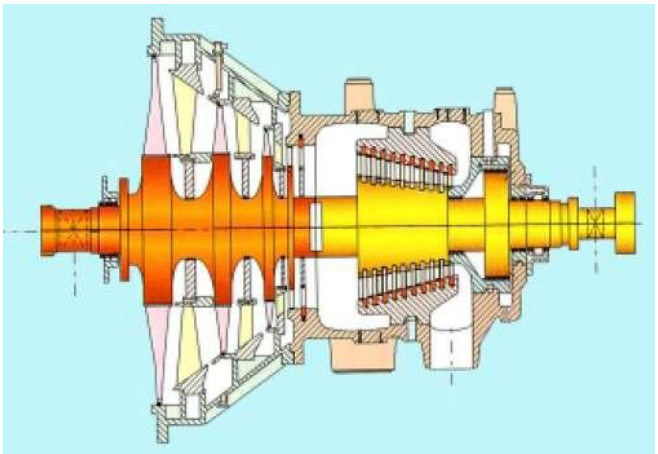


Figure 109. Welded rotor

## 4. What are the advantages of welded rotors?

A.) Welded rotor is a composed body built up by welding the individual segments, so the limitations on forgings capacity do not apply.

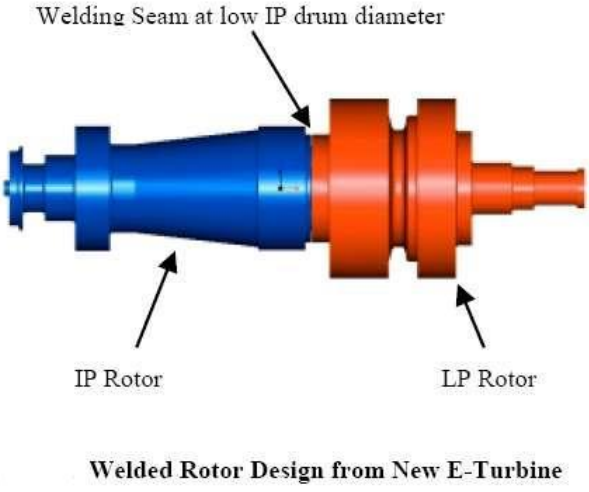
B.)Welding discs together results in a lower stress level. Therefore, more ductile materials can be chosen to resist stress corrosion cracking attack.

C.) There are no keyways. So regions of high stress concentrations are eliminated.

Figure 110. Individual rotor disks are stacked prior to welding. (*Asea Brown-Boveri, Baden, Switzerland*)

Figure 111. Welding the rotor as the rotor turns on a vertical axis

Figure 112. Electrical heat treating blankets on the welded rotor for stress relief




Welded Rotor Design from New E-Turbine

Figure 113. Intermediate rotor welded to the low pressure rotor

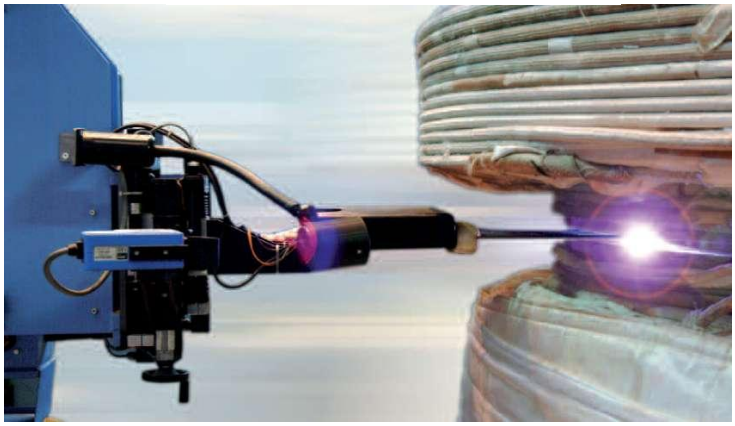


Figure 114. Automatic welder with stress relieving electric blankets in place

## 5. Are turbines ever made with hollow shafts?

Yes. Stiff shafts or rigid shaft are often used on reaction turbines. They are sometimes hollow bored for even heat distribution. S&V says reaction or impulse reaction turbine rotors are one (1) piece solid steel forgings or hollow drum section depending on horsepower. In cases of solid rotors, holes are drilled through on its axis for internal inspection.

Note: When rotors are forged impurities and imperfections tend to collect in the center of the rotor. Center boring was a way to remove these imperfections. Also center boring reduced the total weight of the shaft. (Bottle Boring)

*D.E.S.C. Turbine Operation page 18*

*Croft Turbines page 56*

Large rotors may or may not have a central bore. In years past, bored rotors were necessary because of limitations of steel making capacity. Stresses and imperfections tend to concentrate in the central bore region of the steel forging and the most practical way of dealing with then was to bore the rotor. Bores also provided other advantages, such as inspection capability. Today, even very large rotors can be made from a single forging.

*Steam Turbines and Auxiliaries. Powers Reprint. June 1989. pages 4-5*

## 6. Why is a hole bored through the axis of a solid rotor?

A hole is bored partway through the axis of a solid rotor for internal inspection. It also removes the impurities that gather there during forging. The hole can be used to hold liquid nitrogen to shrink the rotor during wheel replacement.

Figure 115. Hole drilled into the center of the solid rotor for inspection of defects

## 7. How do you balance a rotor?

When it is necessary to balance a rotor in the field it is run up to speed, the high spot is marked, and counterweights are added by trial and error method until balance is obtained. This method is used on both rotors and wheels. This is called Dynamic Balancing.

*S&V page 123, Kents page 8 - 38*

## 8. What are balancing weights? How are they used?

Balancing weights are weights which are placed on the rotor periphery to aid in getting the rotor as near perfectly balanced as possible.

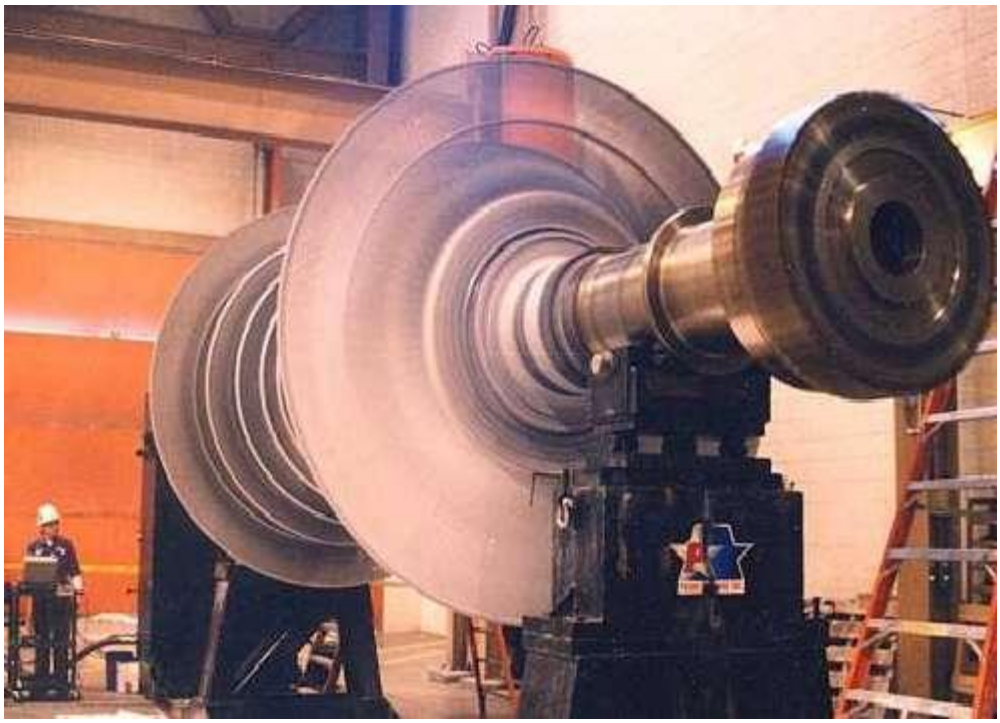


Figure 116. Balancing a large turbine rotor

Figure 117. Balancing a medium sized turbine rotor

Figure 118. Balancing a small rotor

Figure 119. Balancing a large rotor

Figure 120. Balance weights added at the center of the picture to balance the rotor. Notice the small sizes of the weights in comparison to the size of the rotor.

Figure 121. Rotor balancer in operation

## 9. How fast do rotors turn?

For electrical generation in the USA, they either run at 1800 rpm driving a 4 pole generator or 3600 rpm driving a 2 pole generator

## 10. What causes the most problems with rotor failure?

Basic causes of the problems are:

1.) Normal wear.

2.) Fatigue failure due to high stress.

3.) Design deficiency.

4.) Aggressive operating environment, either temperature or chemical

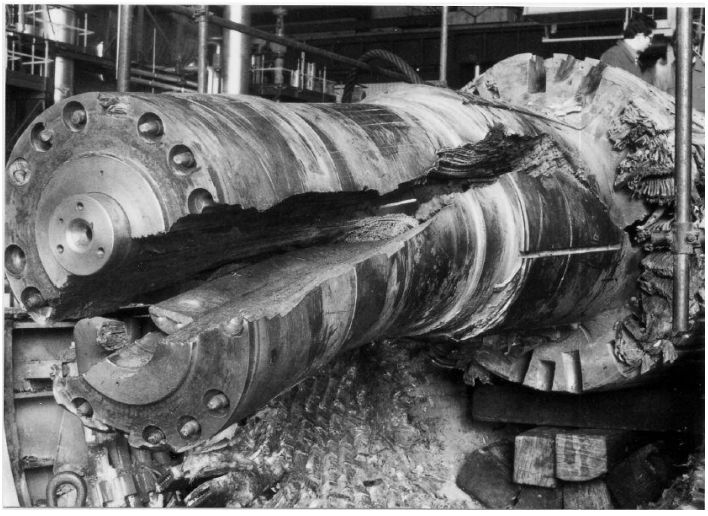
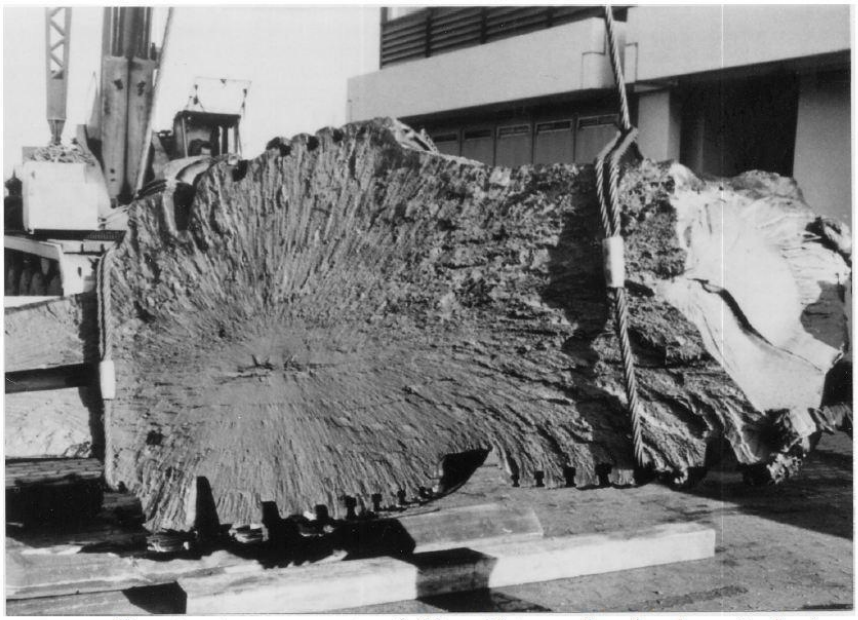


Figure 122. Defective rotor split at the centerline causing a catastrophic failure



**Burst rotor segment weighing 24 tons showing bore inclusions and cleavage planes.**

Figure 123.

Wreckage of 330 MW Turbine-generator from LP rotor burst.

Figure 124. Catastrophic failure

## 11. What are the stresses to which a steam turbine rotor is subjected during its service life?

A.) Mechanical stress is the centrifugal forces and torque generated due to revolving motion of the shaft as well as bending arising during steady-state operation.

B.) Thermal stress – Starting and Stopping without following the manufacturers guidelines for "soaking" periods (letting the turbine for a specified time at a fixed speed to thoroughly warm up the rotor) can create thermal stress in the turbine shaft.

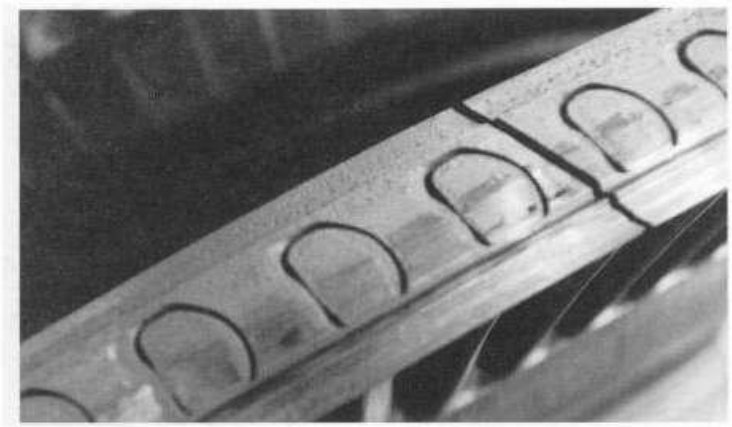
C.) Electrically induced stress originates due to short circuits and faulty synchronization.

## 12. Why does mechanical stress occur in turbine rotors?

The factors that contribute to mechanical stress in the shaft are the centrifugal forces and the torque generated due to the revolving motion of the shaft as well as bending that can arise during steady-state operation.

## 13. What harm occurs from overspeeding the rotor?

An oversped rotor grows radially causing heavy rub in the casing and the seal system. As a result, considerable amount of shroud-band and tenon-rivet head damage occurs.



*Rubs on the inner coverband of stationary blades. These rubs are not normally damaging to the coverband, but will deform the knife edge of seal strips. The casing carrying these stationary blade elements should be checked for concentricity.*

Figure 125. Shroud band rub damage

Figure 126. Shroud Band damage from overspeeding

## 14. What types of cracking occur in the low pressure rotor shaft?

Radial axial-bore cracks.

Circumferential cracks

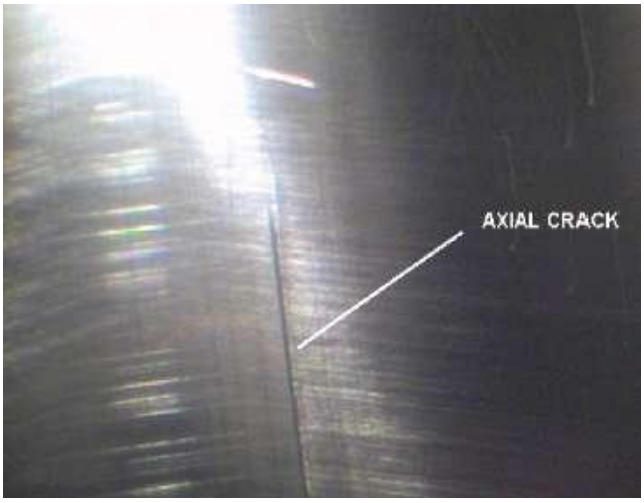



Figure 127. Axial Crack

Figure 128. Circumferential crack at keyway

## 15. What is the cause of axial-bore cracks?

Inadequate toughness of rotor steel and transient thermal stresses

## 16. How are rotors tested for cracks?

They are tested for cracks by the magnaflux method and a visual inspection using a borescope for rotors with holes drilled partway through them.

Figure 129. Using the borescope to check for rotor cracks through the hole drilled partway through the rotor

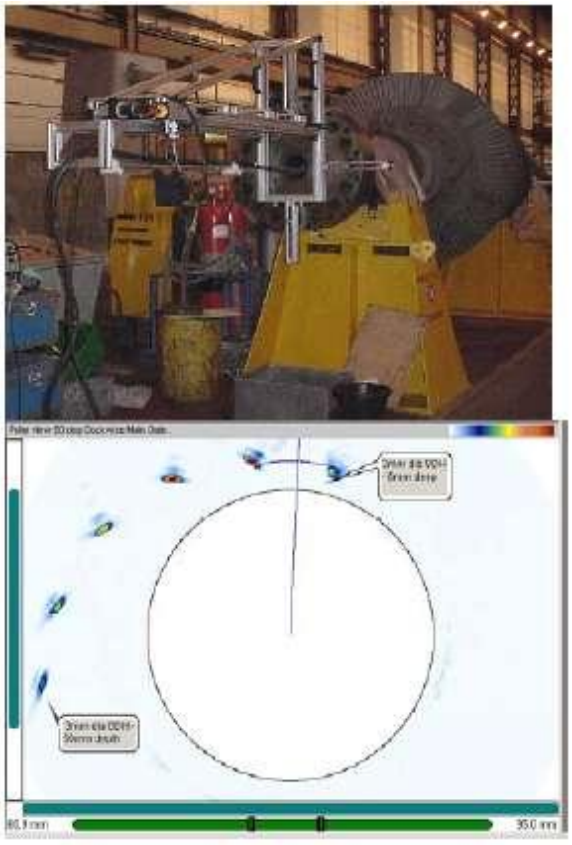


Figure 130. Borescope and monitoring screen

## 17. In which section of the steam-turbine rotors is the problem of rotor failure mostly prevalent?

Rotor failures occur mostly on the large low-pressure rotors, although they are also known to occur in high pressure and intermediate pressure rotors. In the early 1960's, rotors were manufactured from forgings that were not "pure" steel and that is why cracks were initiated at the sites of inclusions, and segregation bands in the steel. This coupled with low inherent toughness of rotor materials resulted in bore cracks.

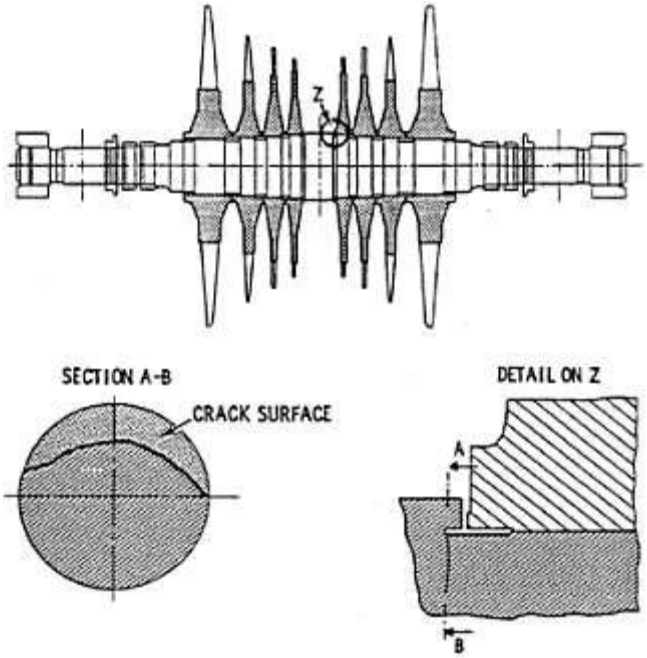



Figure 131. Low pressure rotor cracking

## 18. What are the causes of radial axial-bore cracks on high pressure or intermediate pressure rotors?

The predominant cause is creep, which may act with or without low cycle fatigue. The cracks result due to poor creep ductility due to faulty heat treatment process.

## 19. What remedial measures you can suggest to cope with radial axial-bore cracks?

For new rotors, modified heat treatment process is recommended while for existing rotors de-rating the turbine or replacement of the rotor may be a solution.

Figure 132. Post weld heat treatment with electric blankets

## 20. What other types of cracking occur in high pressure or intermediate pressure rotors that cause rotor failures?

Blade-groove-wall cracking.
Rotor-surface cracking.

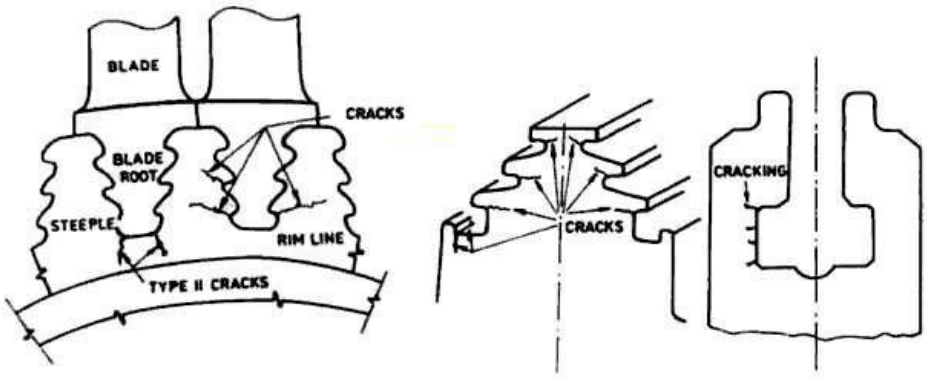



Figure 133. Cracking at the steeples

## 21. What is the nature of rotor surface cracks in steam turbines?

They are shallow in depth and have been located in heat grooves and other small radii at labyrinth-seal areas along the rotor.

## 22. What is the remedy for rotor-surface cracking?

The rotor or shaft should be machined off (skin-peeling).

## 23. Why do these two types of cracking take place?

Whereas thermal fatigue have been identified as the single cause to rotor-surface cracking, mechanical stresses cause axial cracks

Figure 134. Axial surface cracking

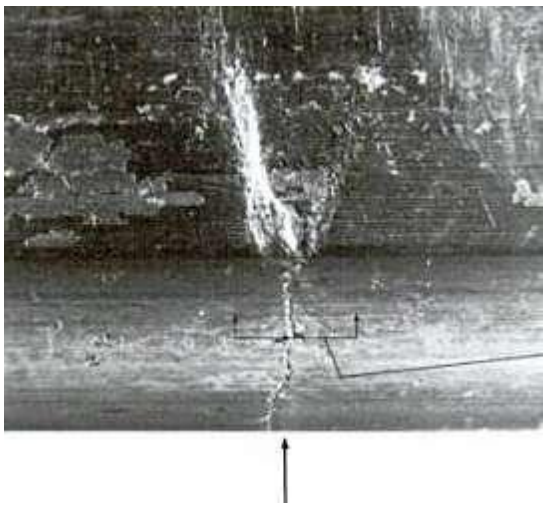


Figure 135. Circumferential cracking

## 24. What is the remedy for a bent steam turbine shaft causing excessive vibration?

The run-out of the shaft near the center as well as the shaft extension should be checked.
If the run-out is excessive, the shaft will have to be replaced. The new rotor should be homogeneous steel and free of impurities. For existing rotors, replace the rotor, grind and overbore.

## 25. Does upgrading of a turbine mean replacement of rotors?

Like the blades, the steam-turbine rotors are highly stressed components. They are subject to cracking by a variety of failure mechanisms. Rotor failures do occur. And when they occur the result is catastrophic with the complete destruction of the unit and the total loss of generating capacity. Therefore, special attention should be given to rotor upgrading and repairing techniques.

Figure 136. Gallatin rotor explosion

Gallatin Unit 2 IP/LP Rotor Fragmentation

The potential consequences of a rotor failure include blade loss due to blade root failure, rotor fracture from a thermally initiated circumferential crack and most significantly, fast fracture from a near bore defect causing a catastrophic burst. There have been only a few instances world-wide of catastrophic bursts of rotors, but the consequences are invariably severe as the fragmented rotor is unlikely to be contained within the casing. Fragments of up to 1000 pounds from the failed Tennessee Valley Authority's Gallatin IP/LP rotor which burst in 1974 pierced the stations' concrete roof. The risk of injury to personnel from flying debris and escaping high pressure steam is therefore significant.

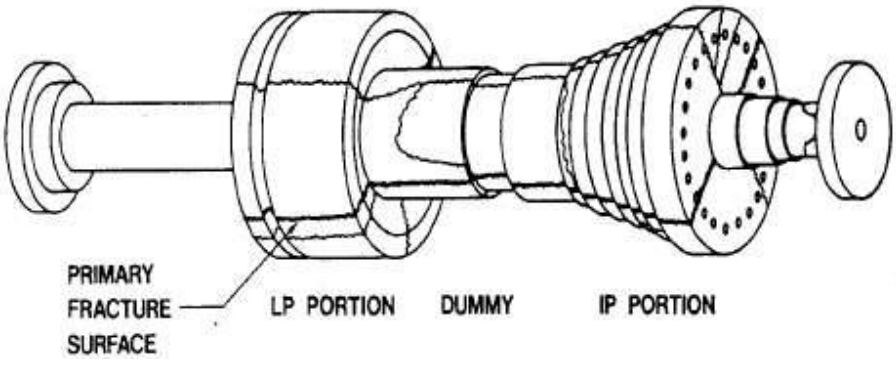
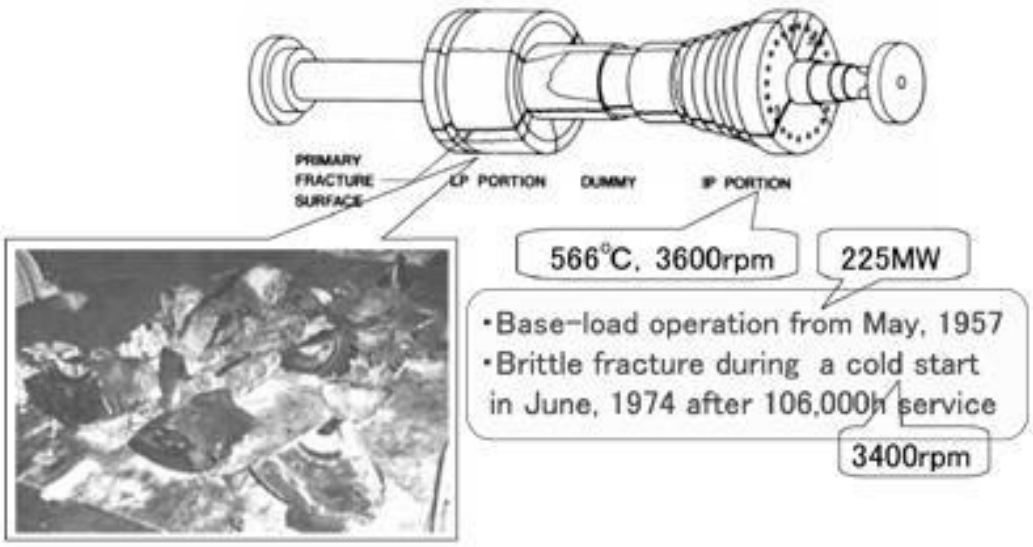



Figure 137. Cracking and fracture lines of the Gallatin rotor

On June 19th, 1974 during a cold start after a long shutdown for repairing the TVA Gallatin No.2 unit, the IP-LP rotor burst at approximately 3,400rpm. The rotor had been in operation for 106,000 hours from its operational start in May 1957. A crack grew due to creep-fatigue interaction during the operation period. Also, the rotor material was degraded by the embrittlement that occurred during the long period of operation. Consequently, the brittle fracture of the rotor during a cold start was caused by the material degradation. Finally, the rotor fractured into thirty large pieces, and some of the pieces flew off to hit the boiler building.




Overview of the burst TVA Gallatin No.2 IP-LP turbine rotor.

Figure 138.

## Creep

Creep-rupture resistance is the primary property critical for the design of high temperature equipment. It may be specified in terms of a stress for a limiting creep strain in a specific time or the stress for rupture in a specific time. Because designs for steam turbines require design lives between 50,000 and 100,000 hours, this usually requires significant data processing.

Creep occurs during steady-state operation due to the centrifugal stresses sustained at high temperature, while thermal fatigue arises from cyclic thermal stresses set up during start-up and shut-down. The most serious threat to the safety of these rotors arises from the possibility that, near the bore, creep cracks may initiate and grow to a size which could result in a brittle fracture of the rotor during a cold start. Initiation may be assisted by any pre-existing forging defects in the near-bore region and growth may be assisted by fatigue due to the thermal and mechanical stresses applied during starting.

Creep cracking can also occur at blade root fixings, leading eventually to the loss of blades and possibly substantial consequential damage to the turbine. Creep, thermal fatigue, and additionally stress corrosion cracking can occur at other stress-concentrating features such as balance holes and changes of section; the effect of any cracking at such features is dependent upon the local stress levels.

## 26. What is the nature of circumferential cracking in shrunk-on-disc rotors in steam turbines?

Regions of high stress concentration give birth to this type of cracking. It begins in corrosion pits and propagates towards the bore by high-cycle fatigue. It may culminate in a catastrophe, if it penetrates the bore (happily this usually does not occur).

## 27. Is there any alternative to the shrunk-on-disc design?

Two designs are available at present:

Welded rotor in which each individual discs are welded, instead of shrunk, onto the main shaft.

Monobloc rotor in which the entire shaft and blade assembly is manufactured from a single forging.

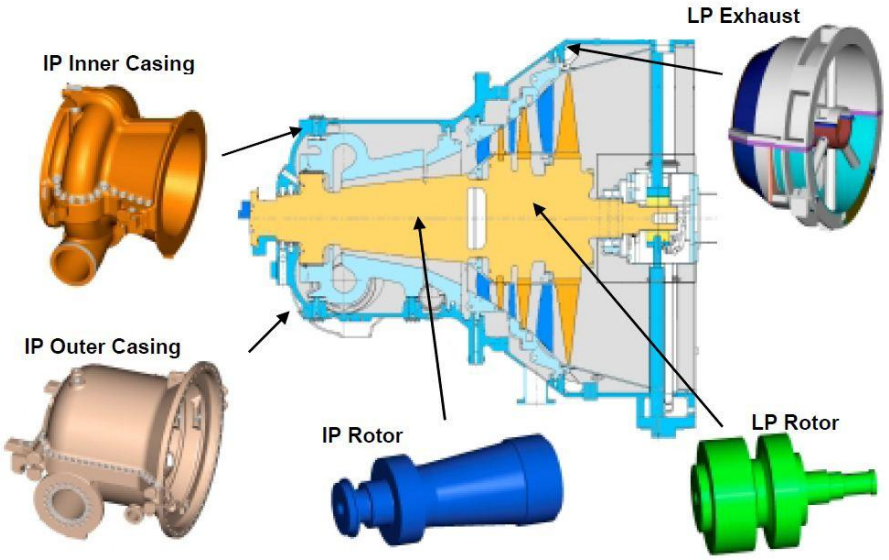



Figure 139. Illustration of the parts needed for a built -up turbine

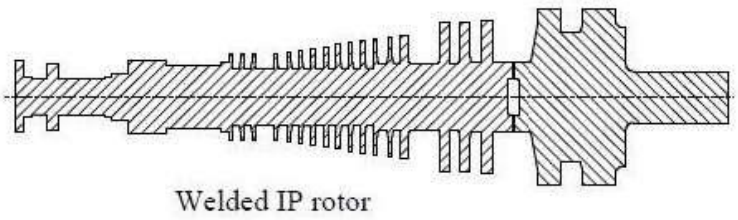



Figure 140.

Figure 141. Submerged arc welding on turbine rotor

Figure 142. Weldng the rotor

Figure 143. Solid monobloc rotor

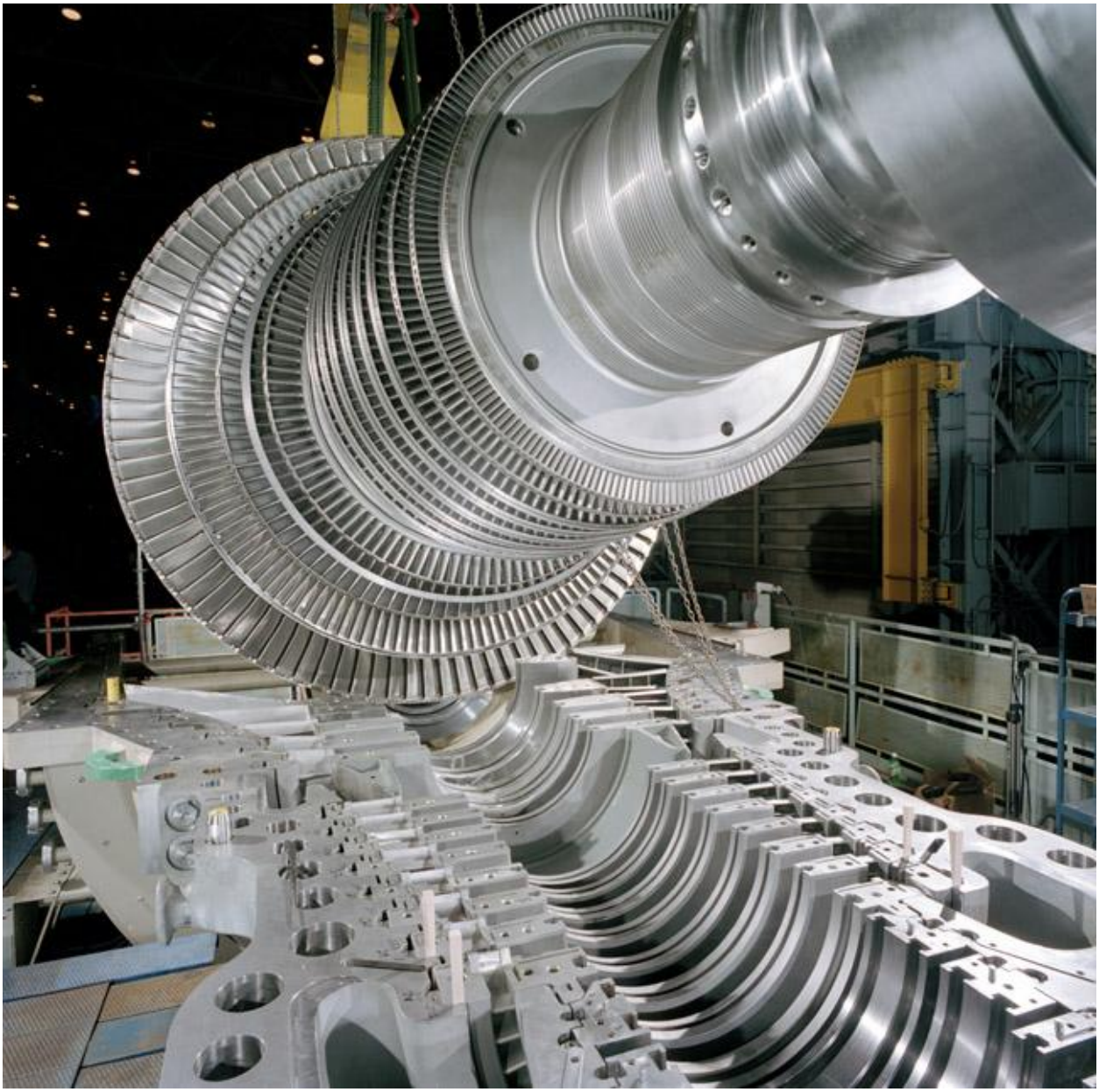


Figure 144. Modern steam turbine rotor and bottom casing

# Chapter 4 Casings and Studs

Figure 145. Steel casting furnace

Figure 146. Pouring the casting

## 1. What is the limit for cast iron construction of turbines?

Cast iron for turbines is limited to 450 F. or less. Higher temperatures cause cast iron to grow and parts to seize.

Figure 147. Starting the cast steel pour

Figure 148. Finishing the pour into the mold

Figure 149. Pouring the cast steel, overhead view

Figure 150. Red hot turbine casing

Figure 151. Another casing after removing from the mold

Figure 152. Large turbine casing just after casting

Figure 153. Turbine casing after cooling

Figure 154. End view of turbine casing

## 2. What are casings made of today? For what temperatures and pressures?

Casings today are made of chrome molybdenum for temperatures up to 950 F. Alloys with 18% chrome and 8% nickel are used for gas turbines at temperatures of 1050 F.

Figure 155. Steel casing after preliminary grinding of rough surfaces

Figure 156. Grinding casting residue away

Figure 157. Checking casing for fit at the flange.

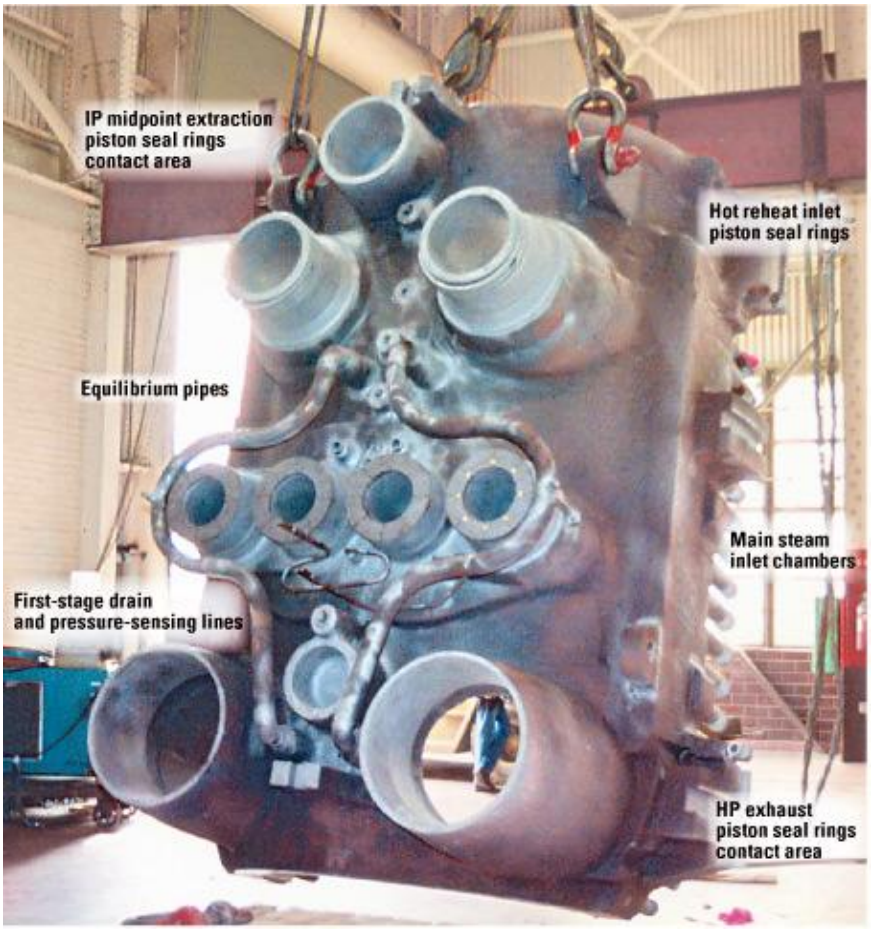

IP midpoint extraction piston seal rings contact area
Hot reheat inlet piston seal rings
Equilibrium pipes
Main steam inlet chambers
First-stage drain and pressure-sensing lines
HP exhaust piston seal rings contact area

Figure 158. Casings must have a large number of openings for attachment of external piping.

Figure 159. Checking measurements on casing

Figure 160. Moving casing with an overhead crane

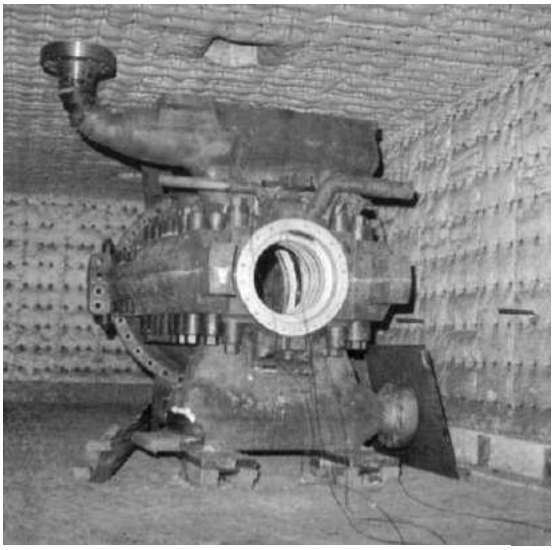


Figure 161. Heat treating the casing in a special oven

Figure 162. Grinding on the rough casting.

## 3. How are casings put together? Why are gaskets not needed?

Casings are made split at the horizontal center line to allow lifting the top half for repair, fabrication, and inspection. The halves are bolted together as a gasketless metal to metal joint. The joint flanges at these sections are hand-scraped to give full metal to metal contact. The best gasket is no gasket.

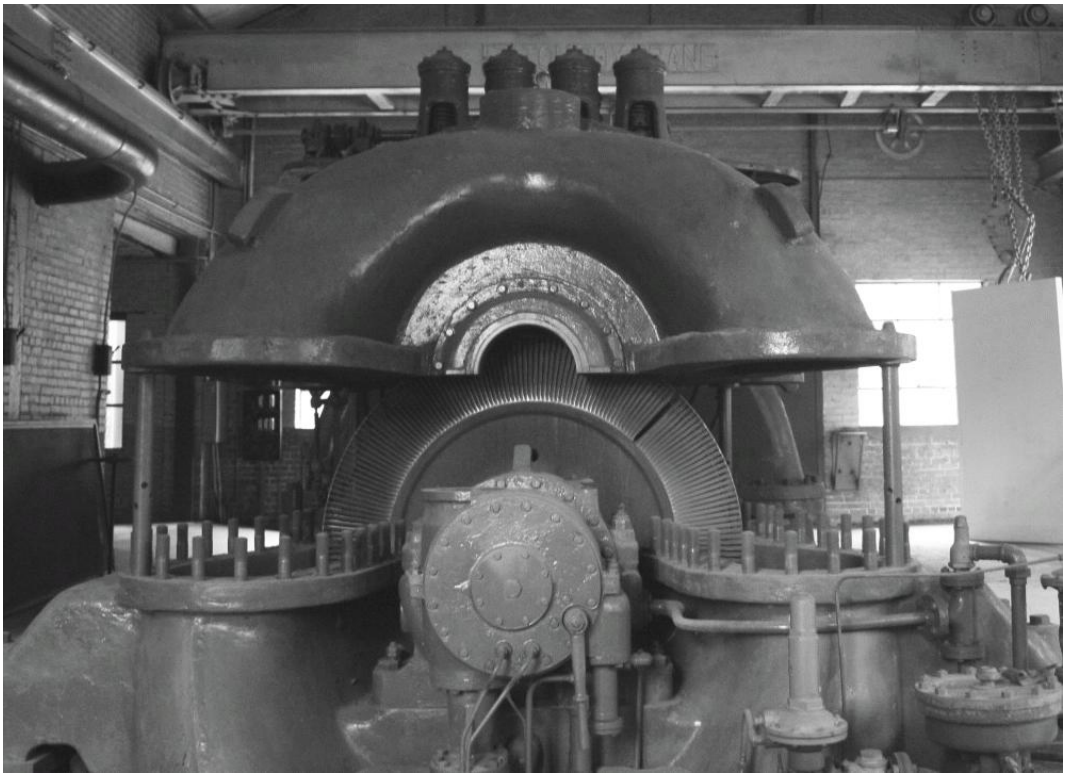


Figure 163. The two halves of the casing fit tightly against each other. Notice the long studs that allow the upper casing to lift straight up without damaging the rotor blading

## 4. How is the joint between the upper and lower halves of the casing made steam tight?

This is a metal to metal joint which has been very accurately machined and scraped to a true surface. The bolts, or studs used to hold the halves of the casing together are threaded by milling in order to obtain smooth thread surfaces. The threads in the nuts are sometimes copper plated to aid in their removal, and these threads are cut with a very slight taper, the reason for this being to obtain more uniform thread loading. Bolts two inches or more in diameter are usually drilled in the center of the diameter to permit heating the bolt before tightening or loosening the joint.

## 5. What is a big advantage of double shell construction? Explain fully this type of construction.

A double shell construction is commonly used on high pressure and high temperature casings. Double shell construction consists of an inner shell with its own bolting, and an outer shell surrounding it. The in-between space is connected to a lower stage of the turbine at a pressure about halfway between inlet steam pressure and the atmosphere. Neither shell is as thick as an equivalent single shell. The inner shell is steam heated on both sides. The advantages of this arrangement are that there is a decrease in distortion when heated, and the unit may be rapidly brought up to operating conditions.

*S&V Pages 63-64*

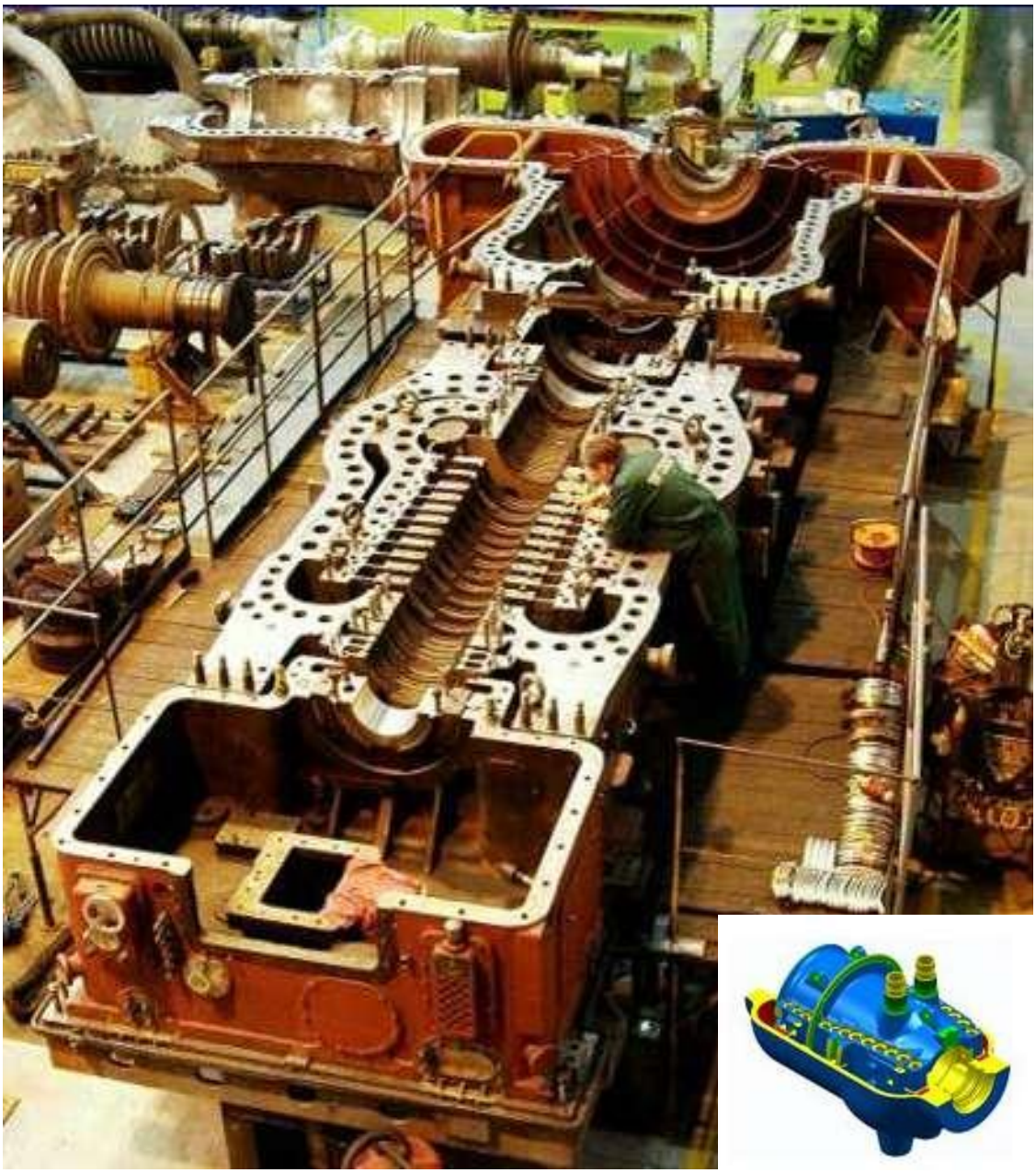


Figure 164. Showing the bottom half of the inner casing and the outer casing



Figure 165. Outer casing bottom and the entire inner casing

Figure 166. Removing the outer casing. Note that the studs and top nuts stay with the upper casing on removal

Figure 167. With the outer casing removed, the inner casing is revealed

## 6. What three methods are used to restore casing surfaces that are excessively eroded?

A.) Metal-spraying.
B.) Welding.
C.) Insertion of filler strips or patch plates.

The manufacturer should be consulted on the metallurgy involved so that the best method can be selected.

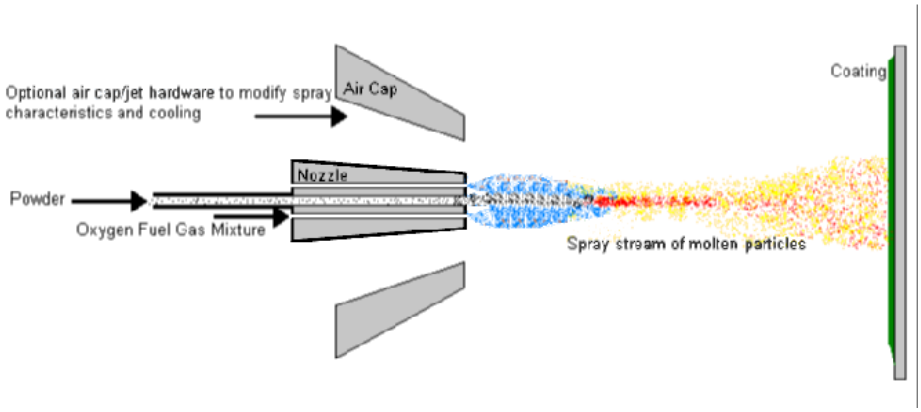



Figure 168. Diagram showing how metal spraying is accomplished

Figure 169. Metal sprayer in operation

Figure 170. Metal spraying a rotor to build up eroded areas

Figure 171. Welding a crack in a steam turbine casing

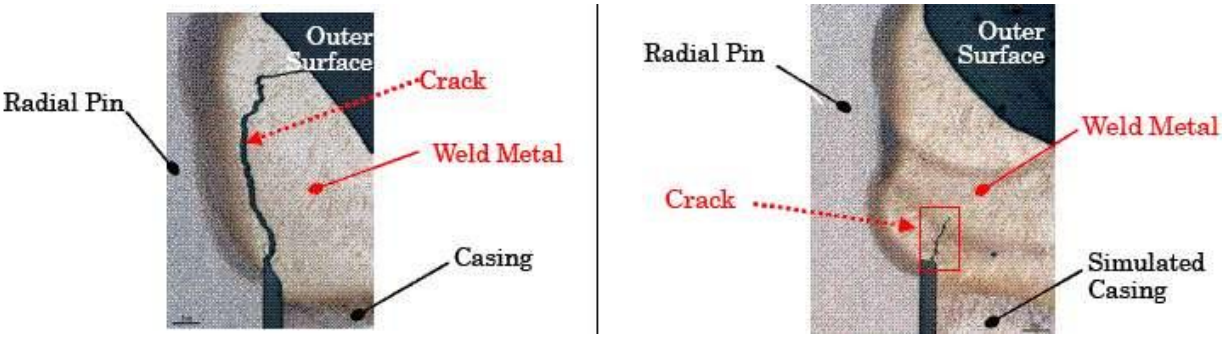



Figure 172. Some welded repairs of turbine casings crack again after repair

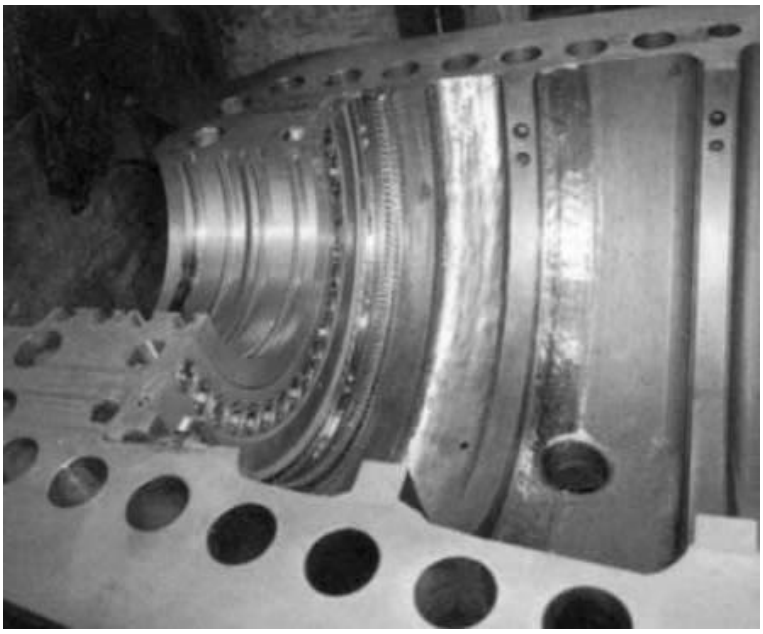


Figure 173. Turbine casing after welding and grinding

GE steam turbine shell with a crack extending from a bolt hole. The crack had a previous weld repair attempt that failed.

Figure 174. Metal stitching repair, drilling holes into the cracked area

The hole pattern for the L60 locks has been drilled across the crack. The locks were installed 125mm deep.

Figure 175. the metal stitching is sitting above the deck, ready to be inserted into the drilled holes

The Locks are driven into the hole pattern to create strength across the crack.

Figure 176. Driving home the locks.

The locks are installed and ready to be machined flush

Figure 177. The locks after rough grinding

The repair was completed in two days. LNS stitched the crack in 1999 and the unit is still in service.

Figure 178. Repaired crack after grinding the stitches smooth

Crack looking up from underneath.

Figure 179. Stitching a longitudinal crack in a turbine casing

Metal stitching the crack

Figure 180. Driving the stitches into place with an air hammer

## 7. How are turbines insulated against heat loss from radiation? What material is usually used?

Turbines are commonly insulated with magnesia over the high temperature section. Steel plates are applied over the insulation to protect it and give it a smooth, finished contour.

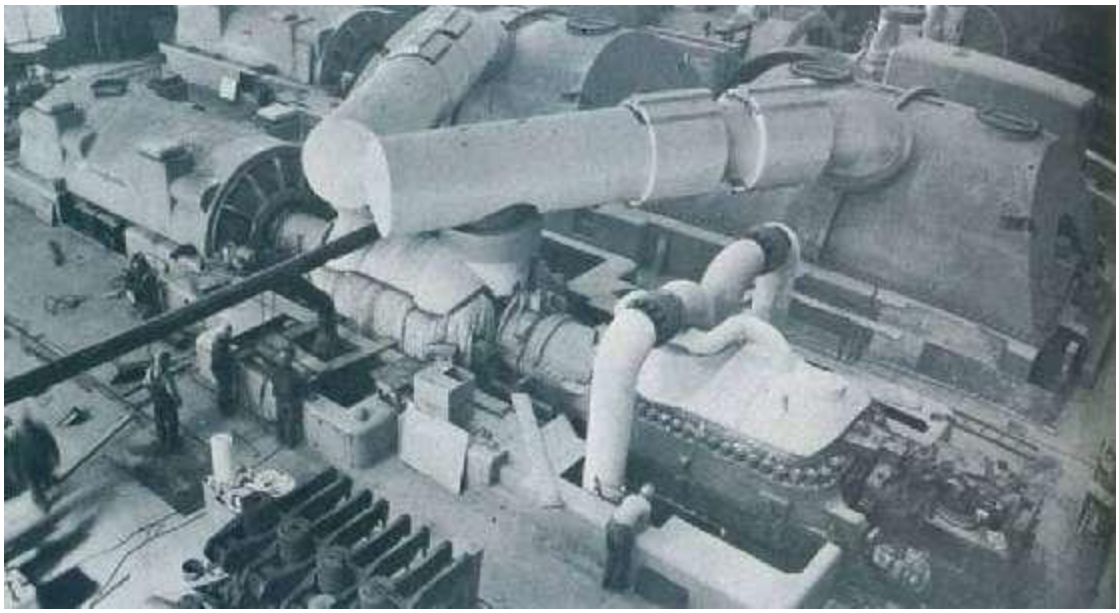


Figure 181. Insulating a cross compound turbine casing

Figure 182. Tandem Compound Steam Turbine with metal sheeting over the piping and outer casing for a nice finished look

## 8. Why is there a relief valve on a turbine casing?

The turbine casing is fitted with spring-loaded relief valves to prevent damage by excessive steam pressure at the low-pressure end if the exhaust valve is closed accidentally. Some casings on smaller turbines are fitted with a sentinel valve, which serves only to warn the operator of overpressure on the exhaust end. A spring-loaded relief valve is needed to relieve high pressure.

A sentinel valve is a valve which is located and designed to allow escape of steam and thereby give warning if the pressure becomes high in the low pressure end of the turbine casing.

*D.E.S.C. Turbines page 3, Croft Turbines page 157*

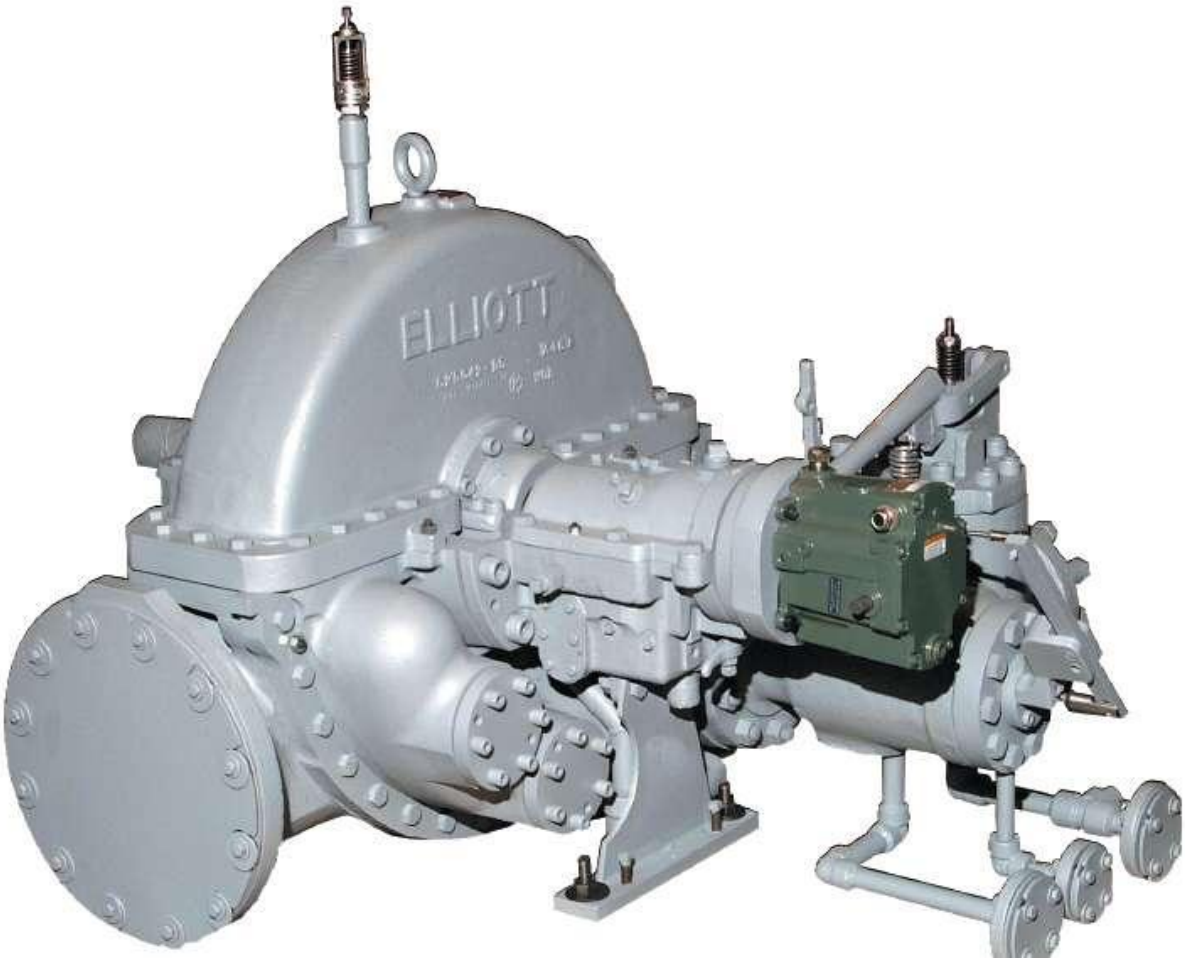



Figure 183. Sentinel Valve on top of Elliott Turbine Casing

## 9. How are large condensing turbine casings protected from overpressure?

By atmospheric relief valves or rupture discs. If you were to lose the condenser pumps, the pressure would rise in the casing. Once it reaches about 5 psi, the rupture disc will release or the atmospheric relief valve will operate.

Figure 184. Rupture disk with protective cage

Figure 185.

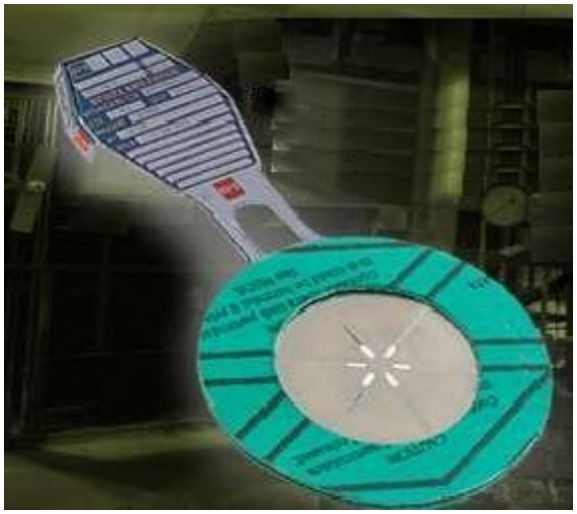


Figure 186. Replaceable rupture disk. Notice the six prescribed cuts to control the rupture

Figure 187. Rupture disc on turbine casing

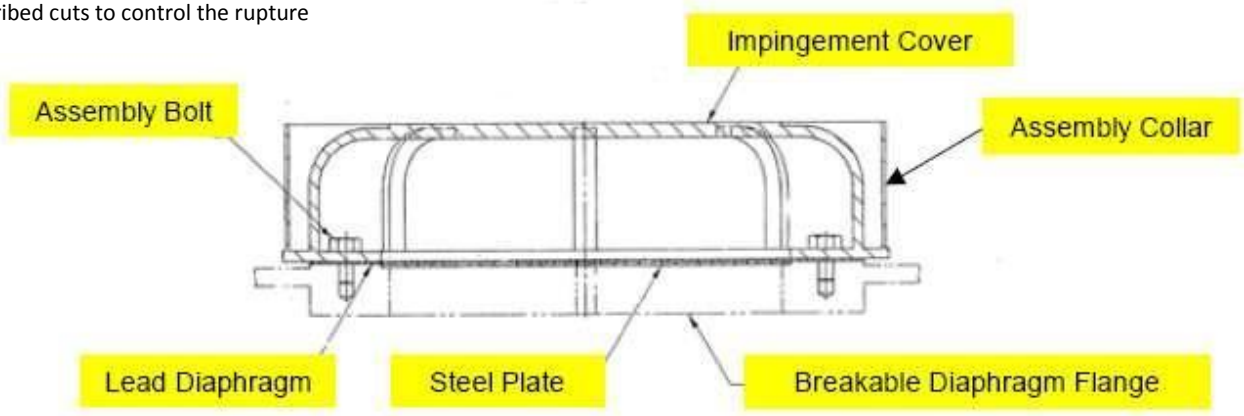



Figure 188. Schematic of a rupture disc

On June 9, 1993, 2 of 4 rupture discs burst, releasing steam into the turbine room at the Commonwealth Edison Quad Cities Nuclear Power Station. This release of radioactive steam burned and slightly contaminated five workers. The rupture discs burst within one second after the turbine was started. Fire doors between the Unit 1 and Unit 2 rooms were blown off their hinges into the Unit 2 room. Both sets of double doors that are part of the secondary containment boundary were also blown open. The floor latch on the inner containment door was bent; the outer doors were also slightly damaged, but were repaired, closed and sealed approximately 35 minutes after the event. The steam release was terminated by automatic isolation of the steam supply line about 20 seconds into the event.

Water had accumulated in the turbine casing because the drain system level switches for the Unit 1 had failed. In April 1992, it had been recommended that the level switches be included in the preventive maintenance program but the recommendation had not been acted on at the time of the event. The slug of water created during the turbine roll passed from the turbine casing to the vertical exhaust line and compressed the air in the 16 inch line containing the rupture discs. The resulting pressure pulse caused the inner rupture disc to burst, which impacted the outer disc as designed and caused it to burst as well.

There are two possible causes for the disc rupture. Either the inner rupture disc was degraded and burst at lower-than-design pressure, or the pressure pulse actually exceeded the design pressure and caused the disc to burst, relieving the exhaust line pressure before the downstream pressure sensors detected a high pressure condition. While inspection of the rupture discs did not reveal any degradation from corrosion or aging, the vendor, Black Sivalls & Bryson, Inc, stated that the discs are warranted for one year of service under normal conditions. The rupture discs at Quad Cities Station had been in service for 20 years and were not part of any scheduled inspection or preventive maintenance program.

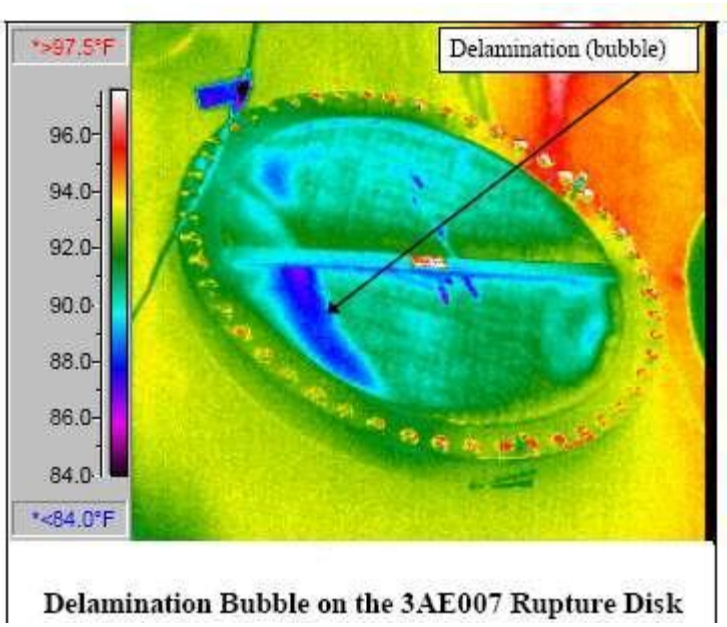



Figure 189. Thermography is used to find rupture discs that have failed. Since they are normally under a vacuum, a failed rupture disc is hard to spot visually.

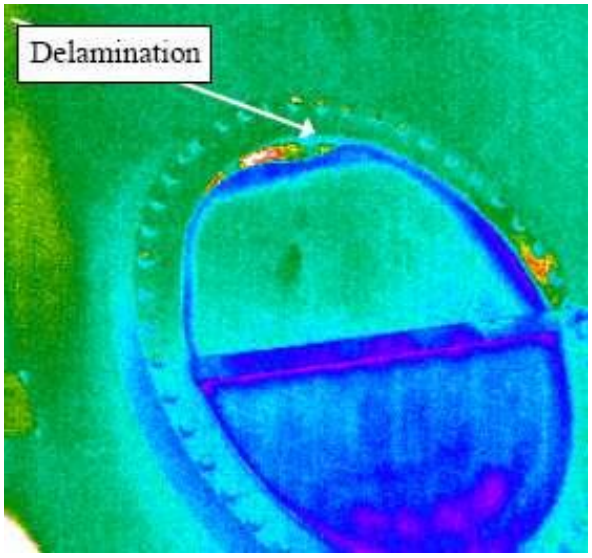



Figure 190. Thermography is using a special supercooled camera to detect temperature differences. This photo shows delamination of the rupture disc at the top.

## 10. How is loss of vacuum handled on a casing of a 10 megawatt condensing turbine?

An atmospheric relief valve is placed on the exhaust end casing of the turbine. This valve provides a means of pressure relief should the casing be pressurized over 5 psi. This valve is vented to the atmosphere and uses condensate as the sealing media. The drains from the water seal are usually returned to the condensate supply line.

*Bob Secorski Mistersky Power Station. Croft Turbines page 156.*

## Atmospheric Relief Valves

Atmospheric relief valves provide automatic protection of costly turbine condenser equipment. These valves are as important as trip throttle valves, overspeed governors, and other devices for power plant protection. Everest atmospheric relief valves are designed and manufactured with the finest materials and the highest quality workmanship.

Water Seal: All valves are equipped with water inlet and overflow ports to provide a water seal around the seat. The overflow port ensures no water head buildup on the disc. A water level gauge is provided outside the valve.

Manual Lift: A side mounted handwheel and screw are incorporated to manually lift the disc for inspection purposes or to keep the valve open for maintenance work.

Operation and Maintenance: Everest Atmospheric relief valves open and close automatically. Each valve needs to be installed vertically and properly leveled for smooth operation. Special “o” ring seals and a water seal is provided for zero leakage in full vacuum conditions. Each valve opens immediately when pressure increases slightly above atmospheric pressure. Higher than atmospheric set pressures can be provided with internally spring loaded discs. During regular maintenance and as many times as possible, each atmospheric valve should be opened by turning the hand wheel clockwise then closing the valves by turning counter-clockwise. This process ensures non-binding and self-cleaning valve action.

Figure 191. Everest Atmospheric valve

Figure 192. Atmospheric valve in an unusual setting

Figure 193. Edwards atmospheric valve showing the sizes to which they can be built

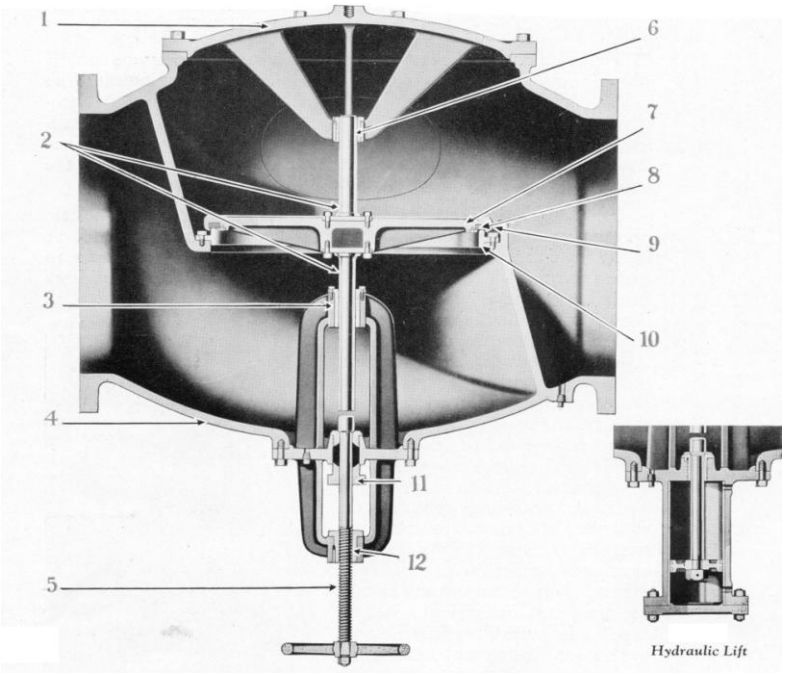



Figure 194. Internal construction of an atmospheric valve

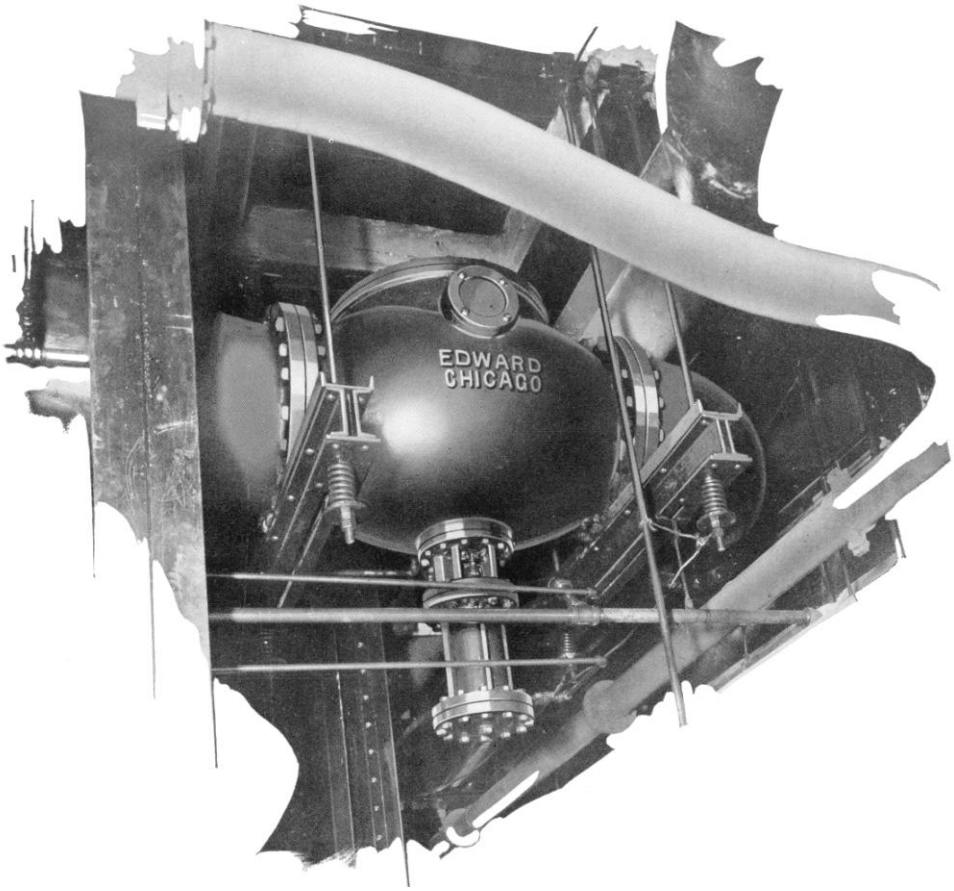



Figure 195. Atmospheric valve installed between the condenser and the turbine

## 11. When should a relief valve be required on the exhaust end of a turbine?

If the manufacturer has provided that the turbine shells are constructed for full-inlet steam pressure for the entire length of the shell. It is absolutely essential to have a relief valve to protect the shell in the event an exhaust valve is closed and high-pressure steam is admitted to the shell on the front end of the machine. Explosions have occurred when this happened.

Figure 196. Large relief valve suitable for installation on a turbine casing

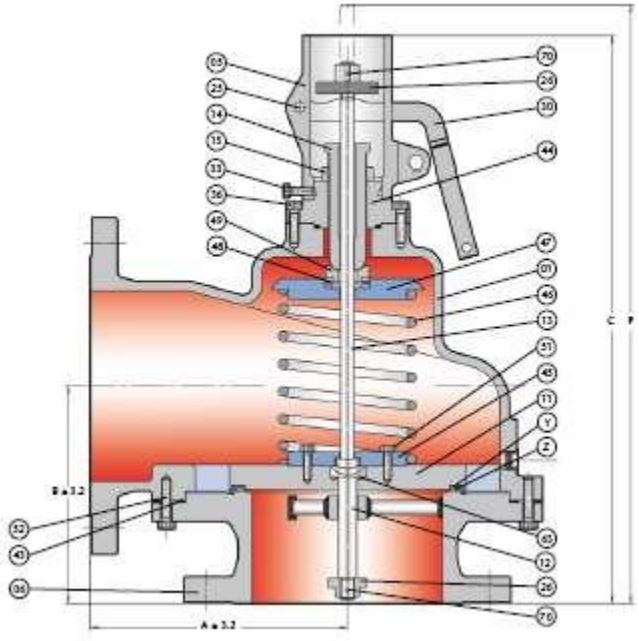


Figure 197. Diagram inside the relief valve

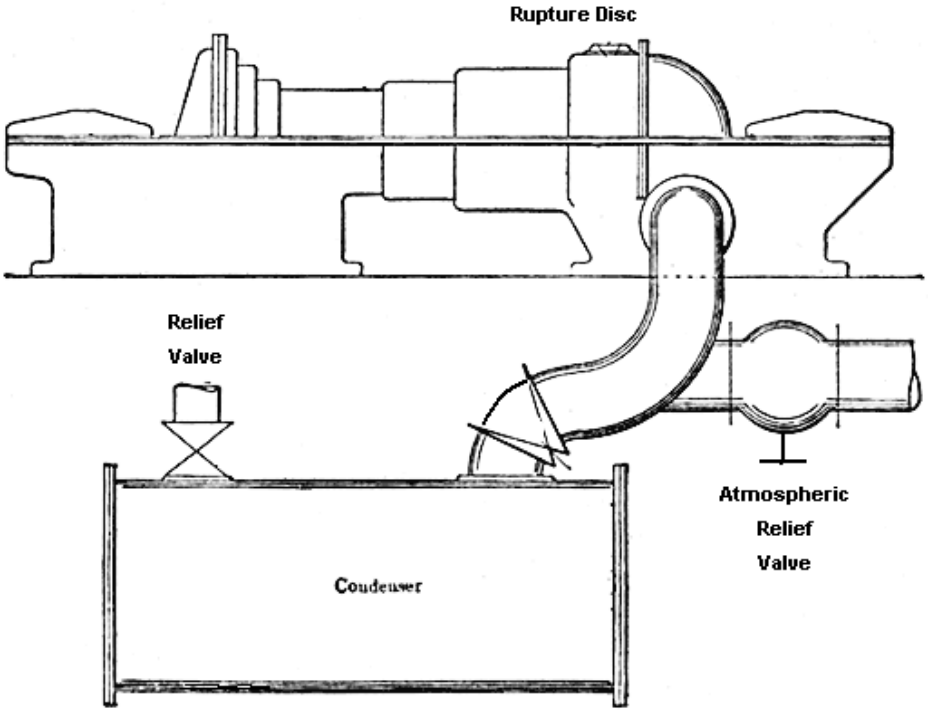



Figure 198. Turbine diagram showing locations of the rupture disc, pressure relief valve and the atmospheric relief valve

# STUDS

## 12. What can you say about studs used in turbine construction?

Turbine studs and bolts are commonly threaded by a milling operation to obtain smooth threads. Other refinements to aid in easy removal are to copper plate the nut thread and use liberal clearance between the nut and stud. Studs over 2" are made hollow and with a slight taper so as to allow for ease of heating in setting up and loosening.

Figure 199. Studs on turbine casing opening

Figure 200. Hollow studs and nuts with a caliper to give you a size reference

Figure 201. Hollow studs and nuts for inserting heaters

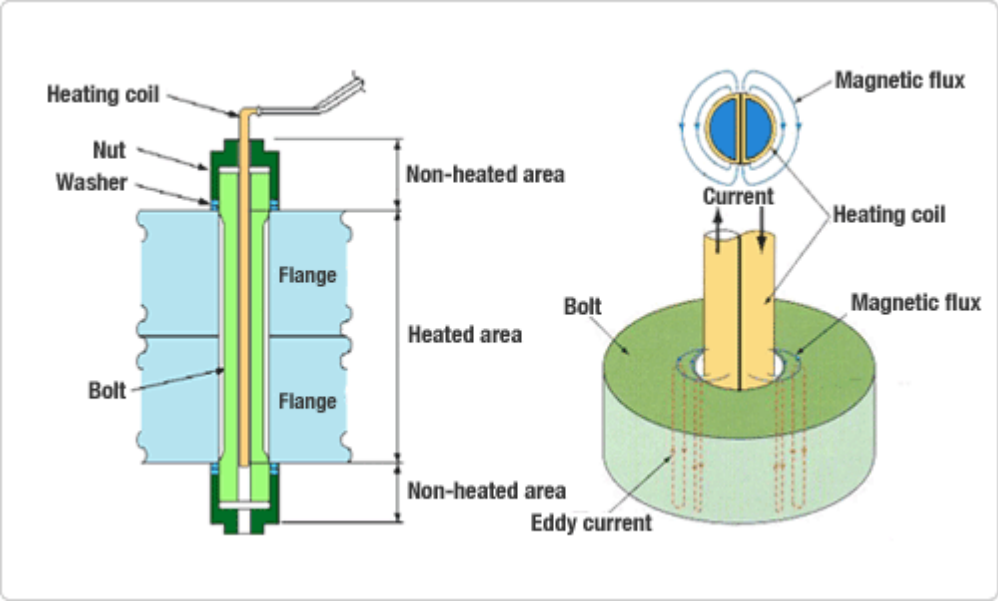



Figure 202. Diagram showing how electrical induction heaters expand the nut to loosen it

3/4" Induction Coil heating a 3 1/2 Dia. x 48" Stud

Figure 203.

Figure 204. Induction heater inside stud

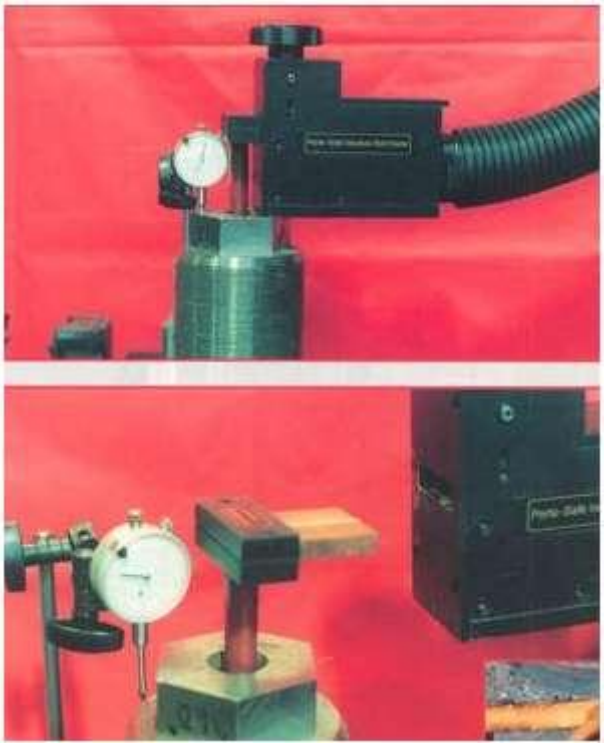


Figure 205. Showing an induction heater with a removable electrical plug for the element

Double loop induction coil for heating nuts when there is no stud hole in the bolt.

Figure 206.

Figure 207. Inserting the heater into the hollow of the stud

Figure 208. Rapping the nuts with a baby sledge

The induction heater is placed inside the hollow of the stud for six minutes to heat and expand it. The sixty pound nut is then hit with a hammer to loosen it. Another worker located below the casing flange uses a special wrench to remove the bottom nut. The top nuts and studs remain in place and are lifted along with the top casing.

Figure 209. Rapping the nut next to the first one

Figure 210. Unscrewing the nuts underneath the ones being hit with the hammer on top

Figure 211. The heating and cooling of the turbine has loosened the nuts

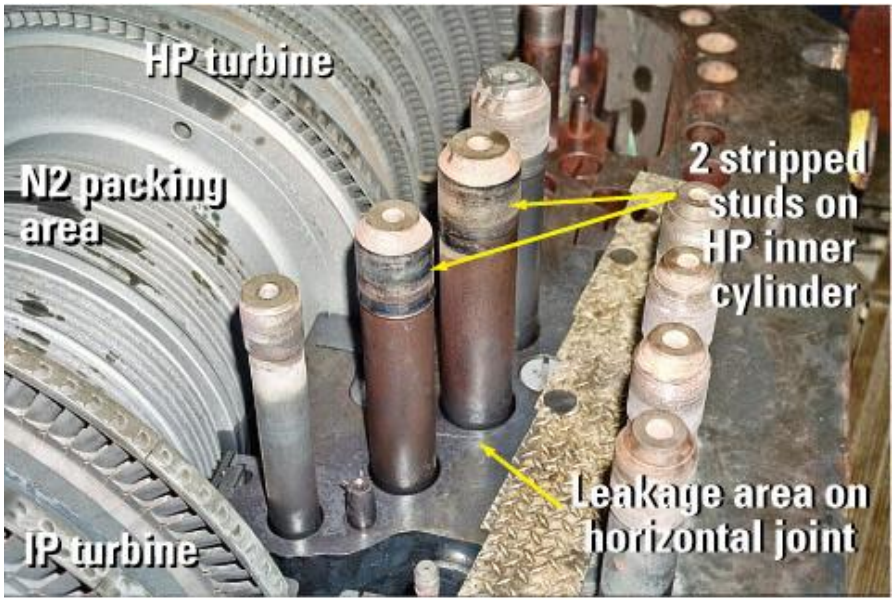



Figure 212. Stripped threads on the studs

Figure 213. Some studs are unbelievably large

Figure 214. Superbolts are a way of tightening large nuts with standard tools

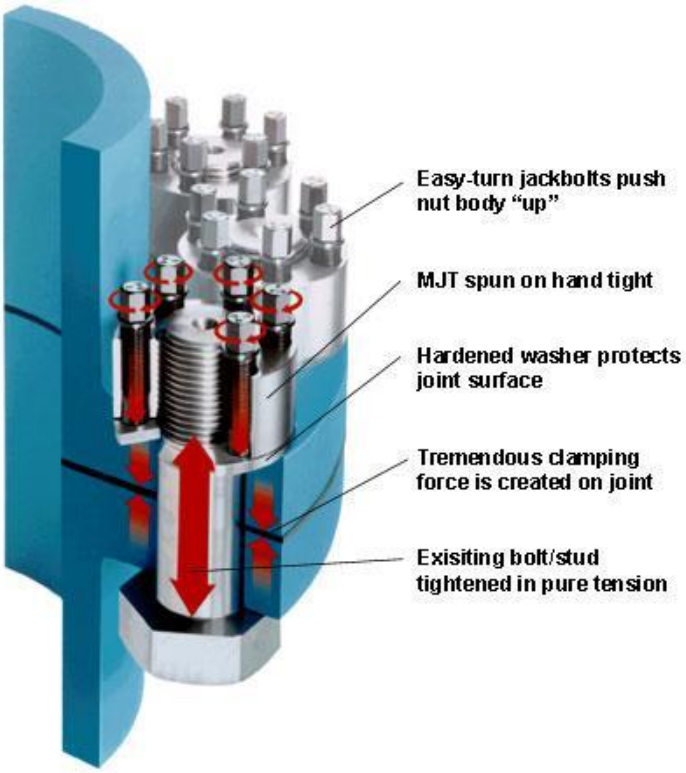

Easy-turn jackbolts push nut body "up"
MJT spun on hand tight
Hardened washer protects joint surface
Tremendous clamping force is created on joint
Exisiting bolt/stud tightened in pure tension

Figure 215. Explaining the idea behind superbolts

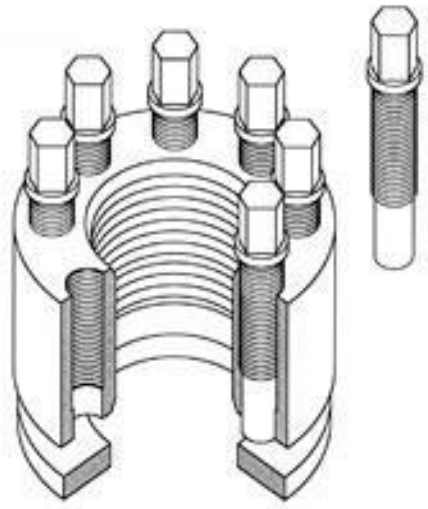


Figure 216. Superbolt cutaway diagram

# Chapter 5 Blades

## 1. Of what materials are turbine blades made?

Blades are made from materials selected for their strength and resistance to corrosion and erosion. Some commonly used are chrome alloy steel, nickel steel, cupro-nickel, stainless steel, and bronze.

## 2. What do the blades of an impulse turbine and a reaction turbine look like?

The blades on a impulse turbine are usually called buckets and resemble crescents, when looking from the top of the blade. The moving blades are mounted on wheels which are attached to the rotor. Stationary and moving buckets are of the same design.

*Grubbs Notes Turbine Section*

Reaction blades are usually called nozzles. They are shaped like a teardrop when looking from the top. This shape forms a nozzle. The blades of a reaction turbine get progressively longer as pressure in the latter stages gets lower. Reaction blades are twisted or warped from root to the tip so steam hits blades with equal velocity. Longer blades show some taper from root to tip.

*McNaughton page 456*

*D.E.S.C. Turbine Operation page 20*

## 3. What are the sizes of turbine blades?

Blades are made in various lengths to accommodate steam volumes as expansion continues through the turbine

## 4. How do they assemble buckets on an impulse turbine?

Rotors have shrunk-on wheels to hold the buckets. The buckets have T-roots on the bottom end of each bucket. These T-roots fit into grooves cut circularly around the outside edge of the wheel through an opening in the wheel that allows them to drop in and slide in a slot around the periphery. They butt up next to each other around the wheel until the last bucket is put in place that will fill the wheel completely with buckets. Then a specially machined bucket is pinned or caulked to the opening to prevent any of the buckets from moving out of the slot.

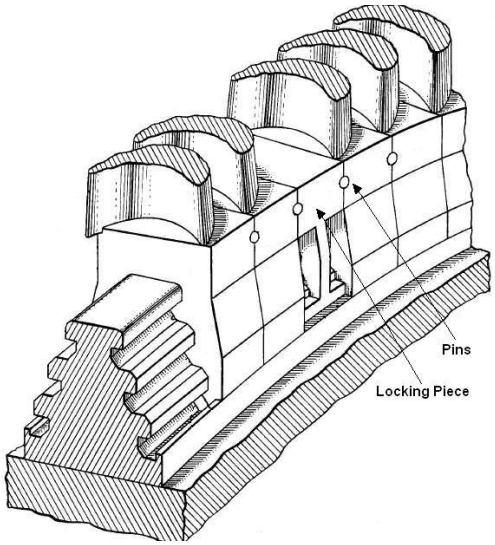



Figure 217. Impulse buckets with fir tree roots, closure piece and locking pins

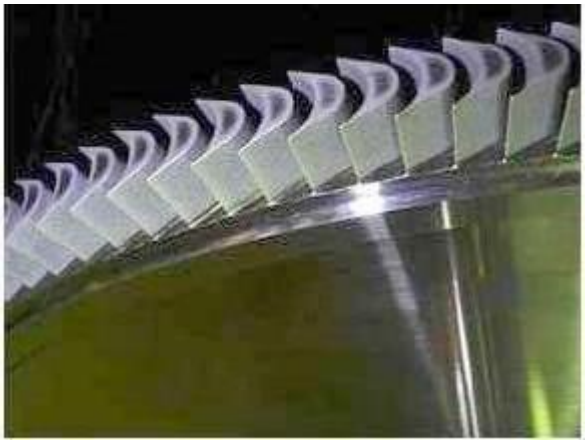


Figure 218. Impulse buckets on turbine wheel

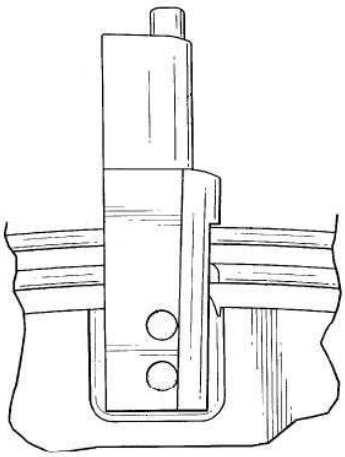


Figure 219. Impulse bucket design with locking pins from the patent drawing.

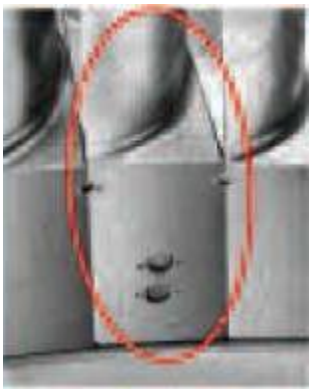


Figure 220. Actual impulse buckets built to the patent design.

The last turbine bucket that fills the wheel is known as a notch piece, closure block, closure blade, closure piece, filling piece, locking piece, or locking bucket.

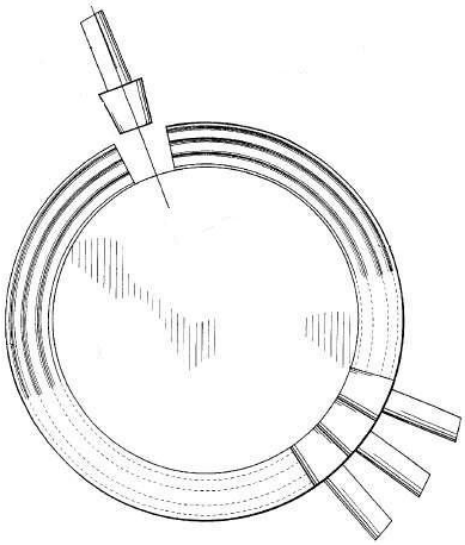


Figure 221. Patent drawing showing how the impuse bucket fits into a notch and then is pushed around the periphery of the wheel

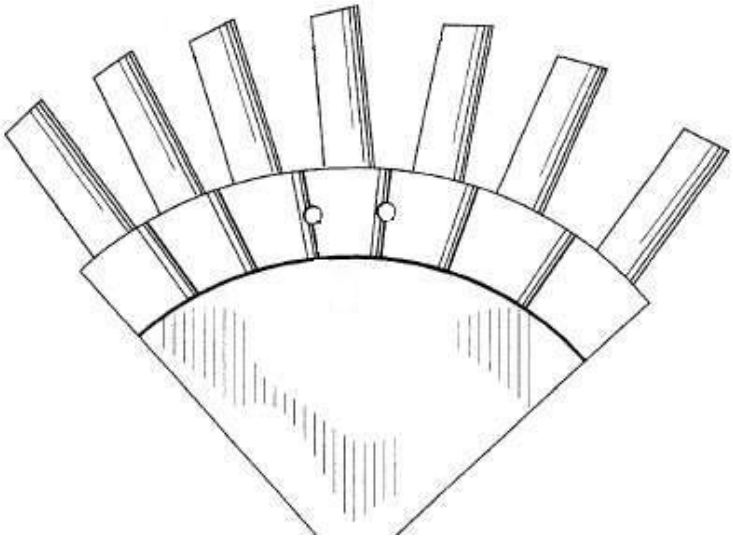


Figure 222. The next-to last and last buckets have half circles that are then pinned to lock all buckets onto the wheel

Figure 223. Actual impulse turbine with locking bucket and pins

Figure 224. Installing blades on the turbine and caulking them in place with brass drift and hammer

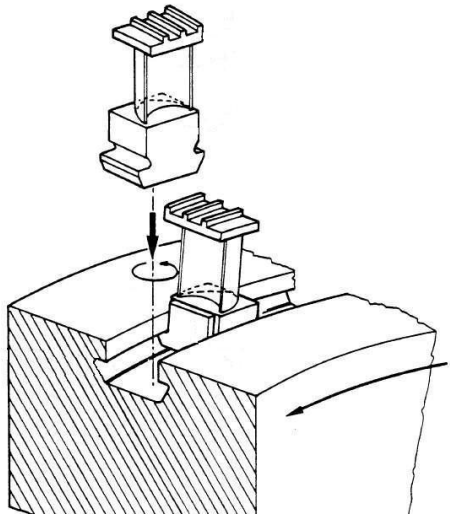


Figure 225. Impulse turbine bucket with T-root and integral shroud. The buckets are turned into the slot

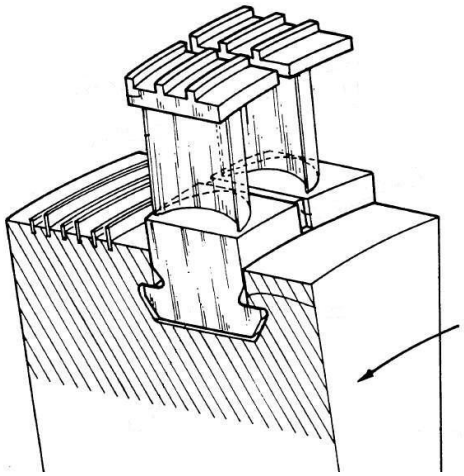
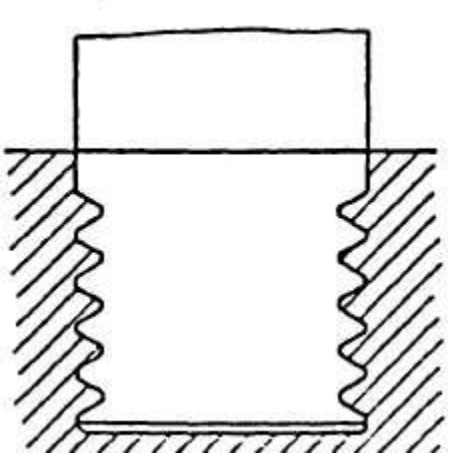


Figure 226. T-root buckets in place on the wheel

Figure 227. Actual bucket built to patent specifications



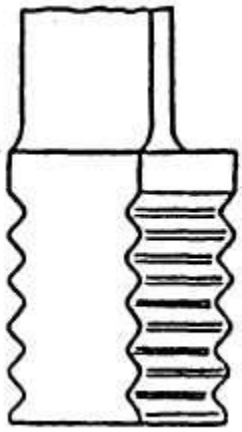


Figure 228. Serrated bucket roots

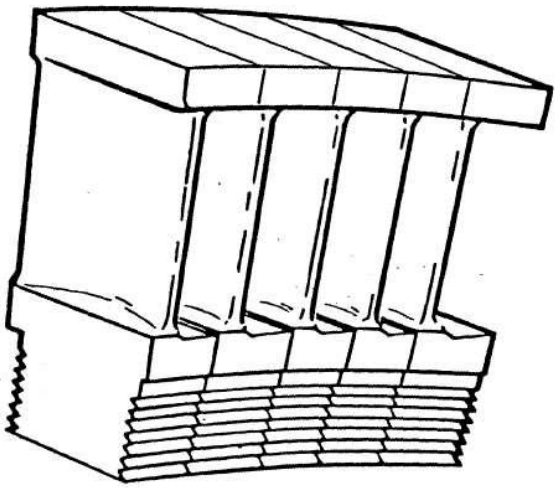


Figure 229. Impulse turbine with serrated roots and integral shroud

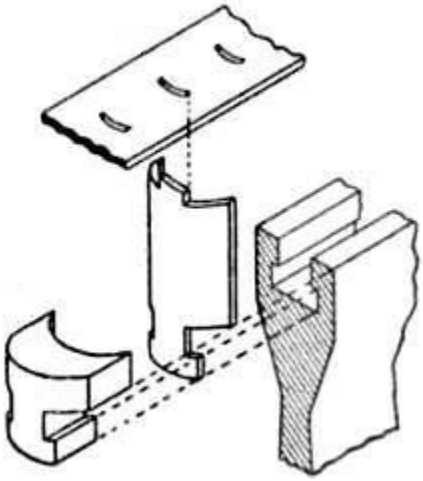


Figure 230. Impulse bucket with 2 piece design and a shroud band to stiffen the blade and keep steam from spilling over the end.

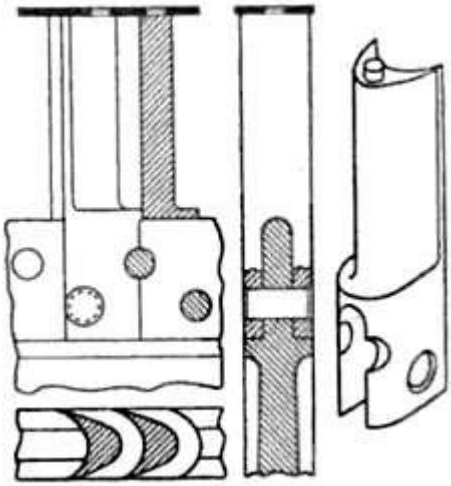
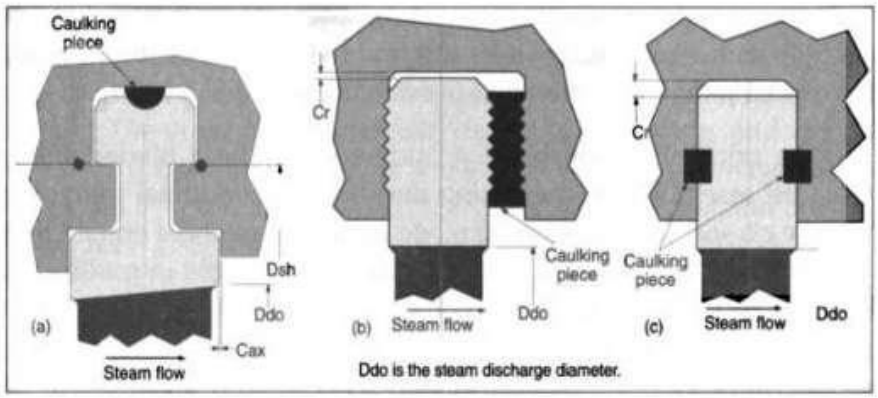


Figure 231. Impulse buckets with an outside dovetail and holes in each bucket for pins to be inserted to hold them in place.




***Methods of caulking the stationary blade elements to secure them against any movement during operation.***

Figure 232.

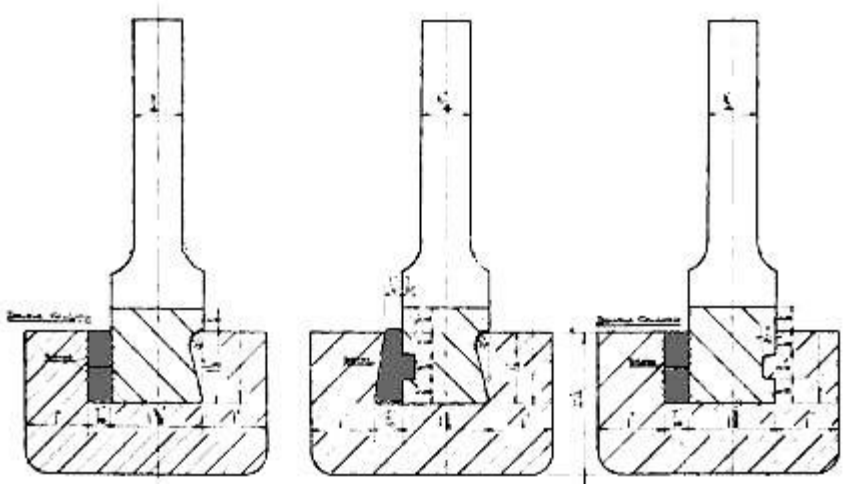


Figure 233. Different styles of caulking pieces to hold turbine blades in place

Figure 234. Caulking blades in place with brass drift and hammer

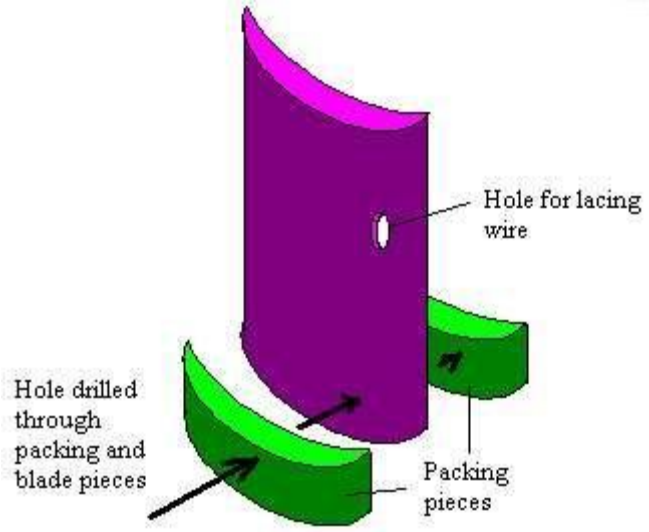



Figure 235. Diagram showing packing pieces to be caulked

## 5. How do they put the blades on a reaction turbine and how are they held in place?

Moving reaction blades are mounted on individual disks. Reaction blades usually are mounted directly on the rotor. Blade fastening methods include: inside and outside dovetail and T-root arrangement. When centrifugal stress and temperature is low dovetailed root fasteners provide ample strength. Blades subjected to high stress are commonly secured by t-root fasteners of either the single or double type. Blades are frequently secured by being held against a shoulder in the groove by half round section caulked in place at the bottom or sides. The blades are usually assembled on wheels or directly to the machined rotor by special blading machines in the turbine builders shop.

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Figure 236. Solid rotor forging for reaction blades with inside dovetail slots milled into the wheels for finger forked blade attachment.

Figure 237. Solid rotor with machining for finger roots

Figure 238. Blade with finger roots

Figure 239. Installing blades with the inside dovetail method. The wheels are forged with the rotor and the inside dovetails are milled out from the wheel. The blades are installed and pins are driven in to hold the blades in position. These are also known as finger roots

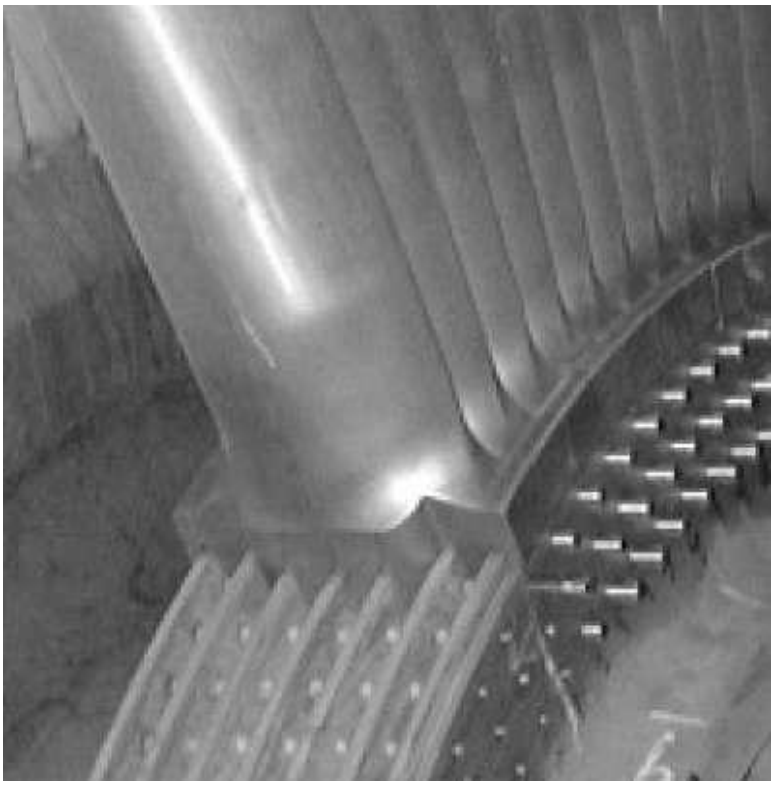

Figure 240. Inside dovetails or finger root blades showing the pins that hold them in place

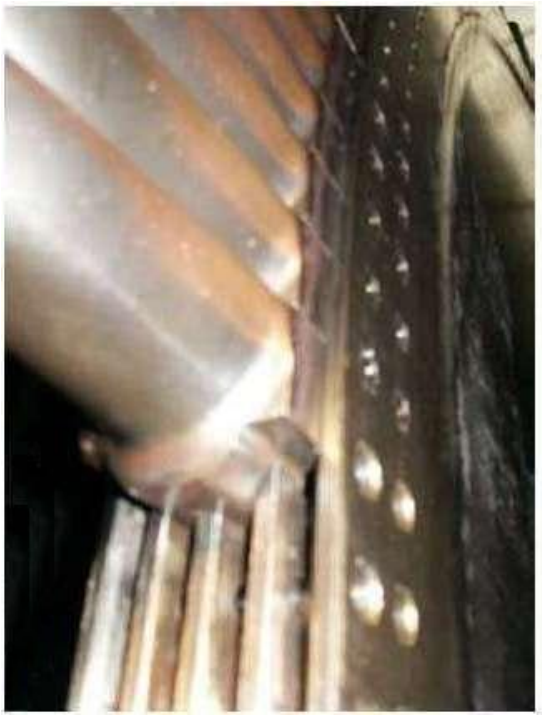

Figure 241. Reaction blading with retaining pins holding each blade in place.

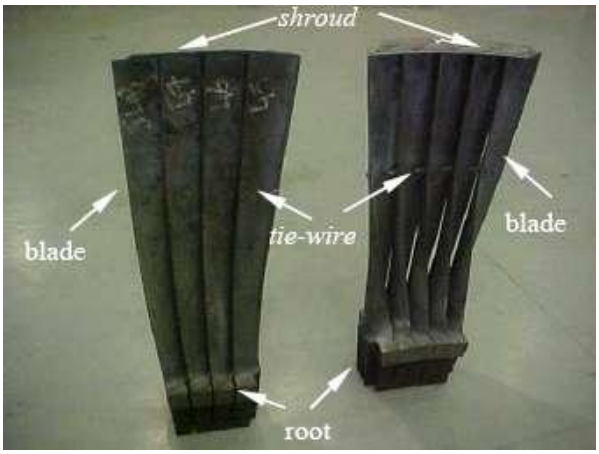


Figure 242 Blades in sections with lacing wire and shrouding

Figure 243. Installing blades

Locking or Retaining pins are used to attach turbine blades in place on wheels or rotors of both impulse and reaction turbines. On impulse turbines, the individual buckets are installed in groves milled on the inside or the outside of the wheels through a gap in the wheel. The last bucket has pins that hold it in position and holds the rest of the buckets tight in their location. The pins and the wheels in modern turbines are normally made from stainless steel.

Reaction turbine blades are installed individually directly on wheels that are forged with the rotor with a multitude of locking pins. Modern reaction turbines use stainless steel in their construction.

Figure 244. Steeples

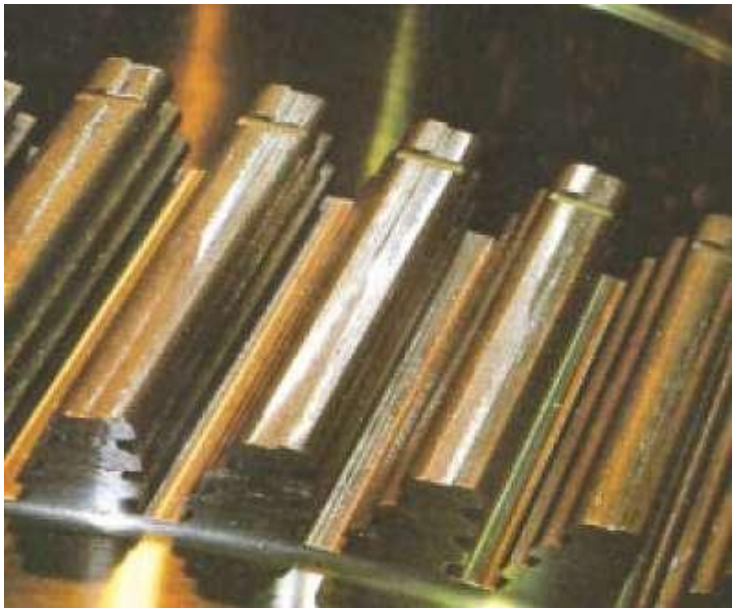

Figure 245. Machined steeples with notch for caulking wire

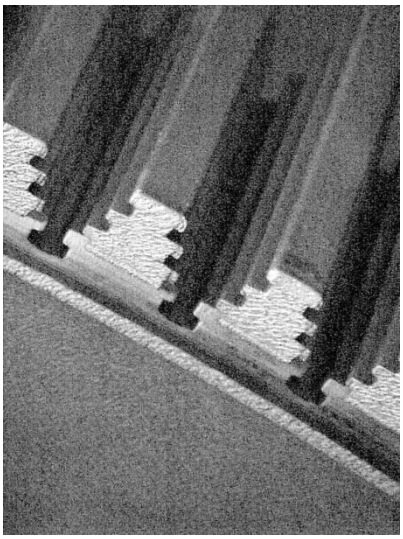

Figure 246. Reaction blading steeples

Figure 247. Blade section

Figure 248. Installing blades on large turbine rotor

Figure 249. Large low pressure stage showing extreme twist of the blade and fir tree root

Figure 250. Installing large blades with curved fir tree roots

Figure 251. Installing blades with straight fir tree roots

Figure 252. Patent drawing showing steeple roots

Figure 253. Actual blades built to patent specifications

Figure 254. Installing blades through the notch that allows access to the wheel

Figure 255. Installing blades

Figure 256. Installing blades

## 6. Why are turbine blades twisted?

Blades are made in various lengths to accommodate the steam volumes, as expansion continues through the turbine. Short blades are generally uniform in width, while longer ones show some taper. Long blades in the final low-pressure stages may be "warped" or of nonuniform section. This permits smooth entry of the steam to the blades.

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## 7. Turbine blades travel faster at the tip, root or middle?

The tip is traveling at a much greater rate of speed than any other part of the turbine. The longer the blades is, the greater its speed.

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Figure 257. Blades are warped to allow the steam to hit each part of the blade at the same speed so that equal work is done on all blade surfaces. The blade is travelling much faster at the tip than at the root

## 8. What is a shroud ring? How is it used?

A shroud ring is a metal band connected to the tips of the turbine blades. It serves to prevent steam from spilling over the ends of the blades as it discharges from the nozzle and flows over the blades. The shroud ring also serves to stiffen the blades.

Figure 258. Impulse turbine bucket with shroud tip before flattening on the shroud band

Figure 259. Shroud bands with square tip and round tips after flattening

## 9. What is the purpose of shrouding?

The tips of turbine blades are often connected by some form of shrouding. This shrouding serves to prevent steam from spilling over the end of the blades as it is discharged from the nozzle and flows over the blades. Shrouding also serves to stiffen the blades or buckets and so prevent vibration of the blades particularly where steam does not flow over the entire annulus of the blades on a wheel, as in the high pressure stages of an impulse turbine. In many designs the shrouding is band slotted to take a projection of the blade tip. This band is then riveted or welded into place. Shorter blades often have integral shrouding formed by the tip of each blade.

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*D.E.S.C. Turbines page 27*

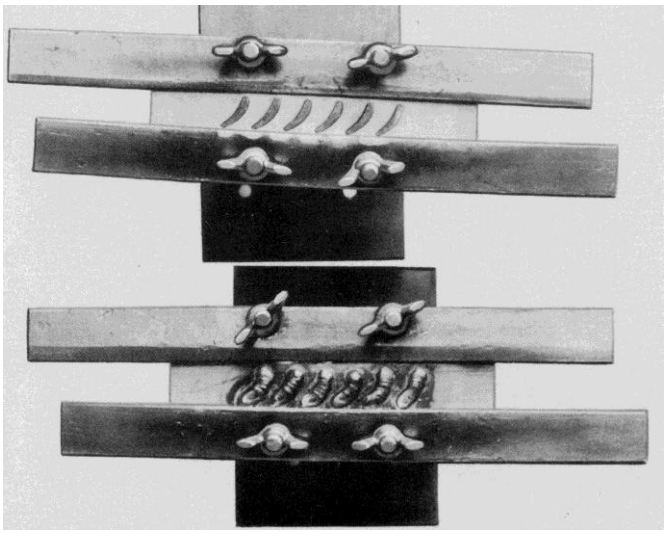


Figure 260. The shroud band is held in place over the blade tips in the upper section of the photo, and then welded in the lower section of the photo

Figure 261. Integral shrouding and fir tree roots on impulse buckets

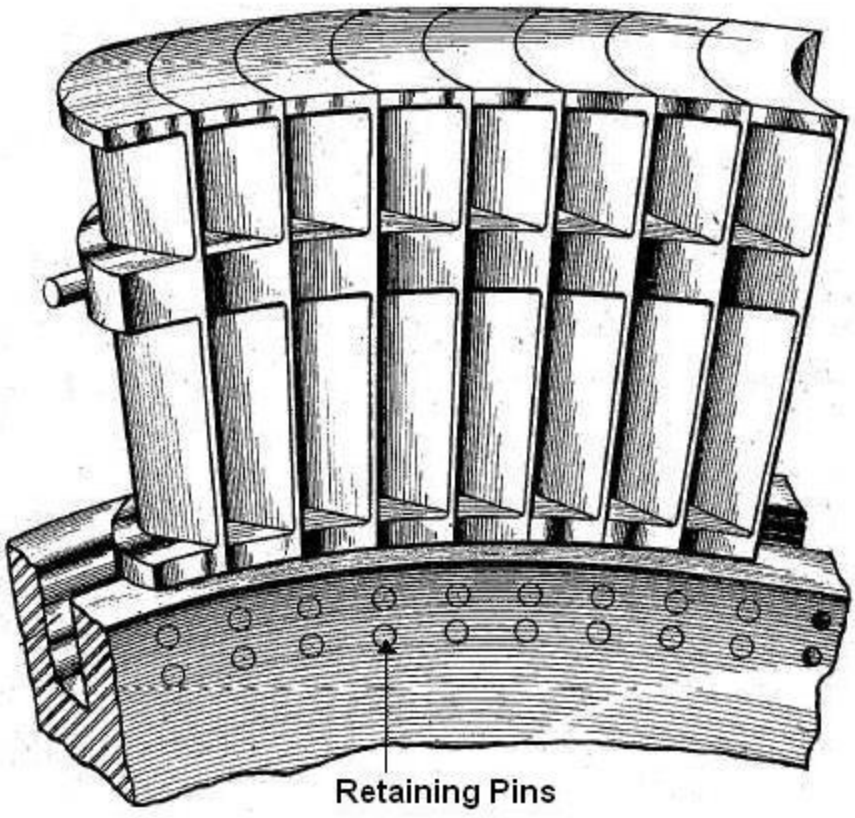



Figure 262. Integral shrouding and retaining pins on impulse buckets

## 10. What material are shroud rings made from?

Shrouding is made from chrome iron alloy, stainless steel and other materials. These are flat metal rings provided with properly spaced holes placed over the ends of the blades and peened over. Purposes:

A.) Stiffens the blades.
B.) Seals to prevent leakage across blade ends.
C.) Prevents casing erosion.
D.) Prevent vibration by stiffening the blades.

*D.E.S.C. Turbines page 27, S&V page 48*

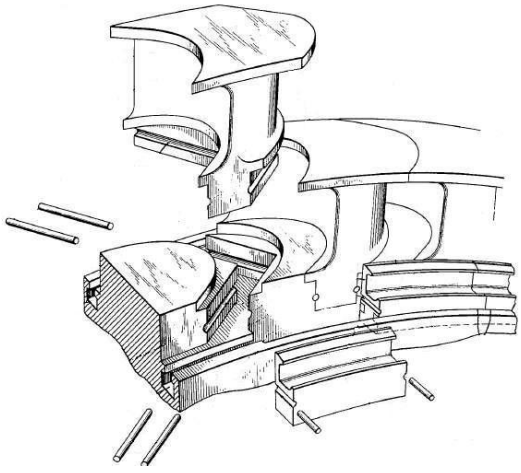


Figure 263. Impulse buckets with integral shroud fit into grooves and then are pinned in place in this design

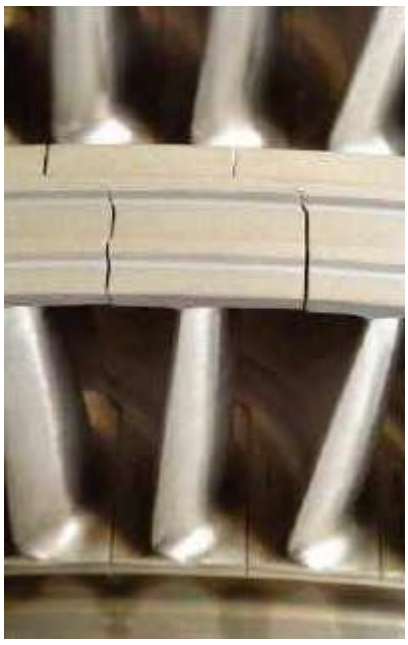


Figure 264. Integral Shroud

## 11. What design modification is adopted to reduce susceptibility of last low-pressure stages to fatigue failure?

One modification is to join the blade segments together at the shroud band.

## 12. How does this modification reduce the vibration fatigue damage?

Joining the blade segments together at the shroud band increases the length of the arc-to a maximum of 360° that alters the natural frequency of the blade grouping from the operating vibration mode. This design has gained considerable success in commercial service.

Figure 265. Shrouding on last stage of a GE turbine

## 13. Why do shroud bands suffer from damage?

Steam borne solid particles and moisture strike the shroud band continually and in the process they remove material from rivet heads until the rivet becomes too weak to exercise its clamping effect whereupon it fails to hold the band in place.

Figure 266. Bucket failure and shroud band failed to hold in place

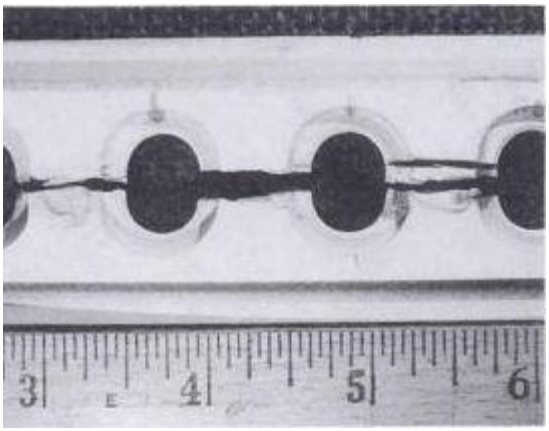



Figure 267. The shroud band cracked and rivets failed to hold it onto the turbine blades

## 14. Why are free-standing blades in the last low-pressure stage favored more in some cases, than those that are coupled and shrouded together?

These free-standing blades are known to provide good and adequate protection against stresses and aggressive environment. They eliminate all the shroud/tenon interfaces and tie-wire hole areas where corrodents can collect.

Figure 268. These last stage blades are free-standing and avoid the problems with shrouds

## 15. What is an erosion shield?

Erosion shields, shaped to fit the blade, are silver soldered to the leading edges of last stage blades. The shield resists the erosion effect of water droplets in the wet steam flowing through the last stages of steam expansion in the turbine.

Figure 269. Attaching stellite erosion shields by silver soldering

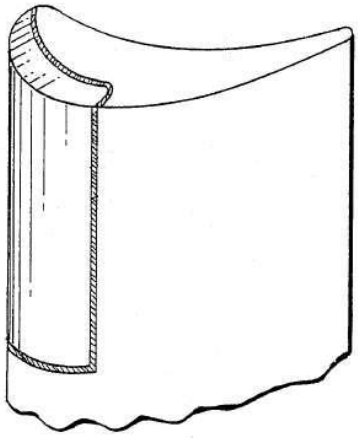


Figure 270. Stellite erosion shield installed on last stage blade

## 16. What are erosion shields on reaction turbines made from?

Stellite is the material used on the tips of the last stages of reaction blading. This extremely hard alloy greatly reduces erosion due to small water droplets in the condensing steam.

*Kents 11th Edition. page 8-23*

## 17. What is honey dipping of turbine blades?

Honey dipping is the practice of silver soldering stellite or tungsten erosion strips or shields to the leading edge of the blades in the last stage wheels of a larger turbine. These shields prevent erosion of blades by droplets of condensate that may form in the last stages. They can be replaced when worn down thus saving the blades. If Inconel is used as the filler material, it has the inferior resistance to erosion in comparison to the Stellite insert. So filler material can erode away underneath the stellite.

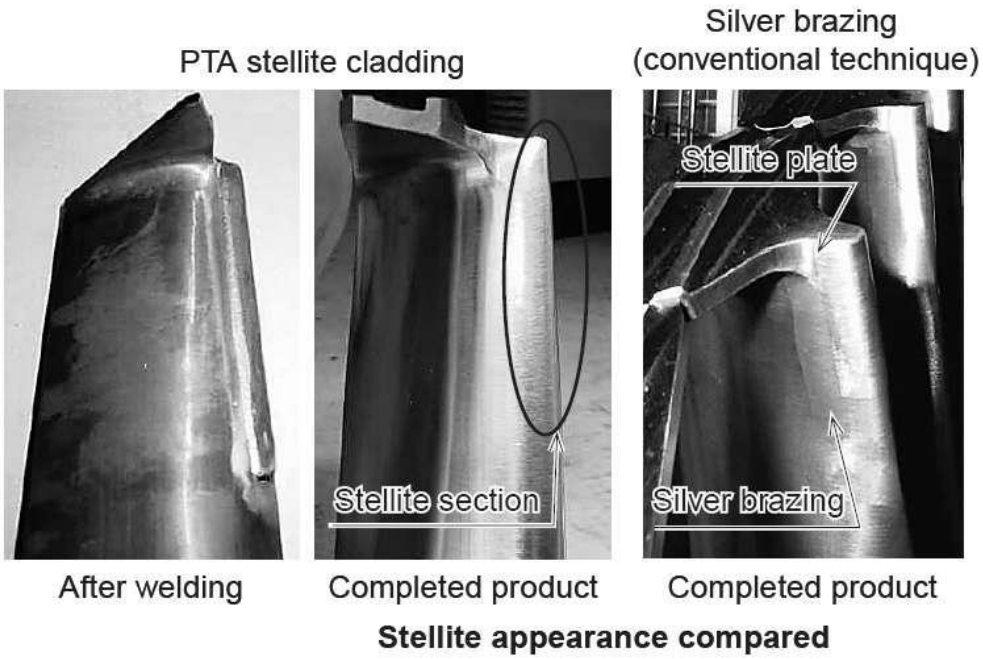



Figure 271.

Figure 272. Erosion on turbine blades tips

The HVOF (High Velocity Oxygen Fuel) Thermal Spray Process is basically a high pressure water cooled HVOF combustion chamber and long nozzle. Fuel (kerosene, acetylene, propylene and hydrogen) and oxygen are fed into nozzle chamber, and the combustion produces a hot, high pressure flame which is forced down the nozzle increasing its velocity. Combustion occurs outside the nozzle. The compressed air pinches and accelerates the flame and acts as a coolant for the HVOF gun. Powder is fed at high pressure axially from the centre of the nozzle. Thermal spraying can provide thick coatings. Such coatings provide protection against high temperatures. It is typically used to deposit wear and corrosion resistant coatings on materials, such steam turbine blades. Common powders include tungsten carbide cobalt, and chromium carbide.

*HVOF coating operator performing coating on the blades.*

Figure 273.

*Finished coating on the two last stage blades.*

Figure 274.

## 18. What are sealing strips?

Metal strips on the ends of shroud bands of turbine blades to prevent steam from leaking across a stage. They can also be on the diaphragm where the rotor passes through the center hole to prevent steam from leaking across a stage.

*S&V page 49*

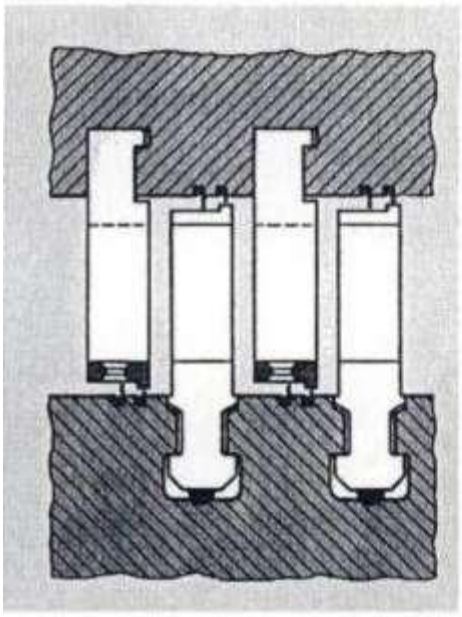


Figure 275.

Cross section of reaction stages showing sealing strips, also called J strips or caulking strips inserted in shaft and blade carrier surfaces. (*Siemens Power Corporation, Milwaukee, Wis. and Erlangen, Germany*)

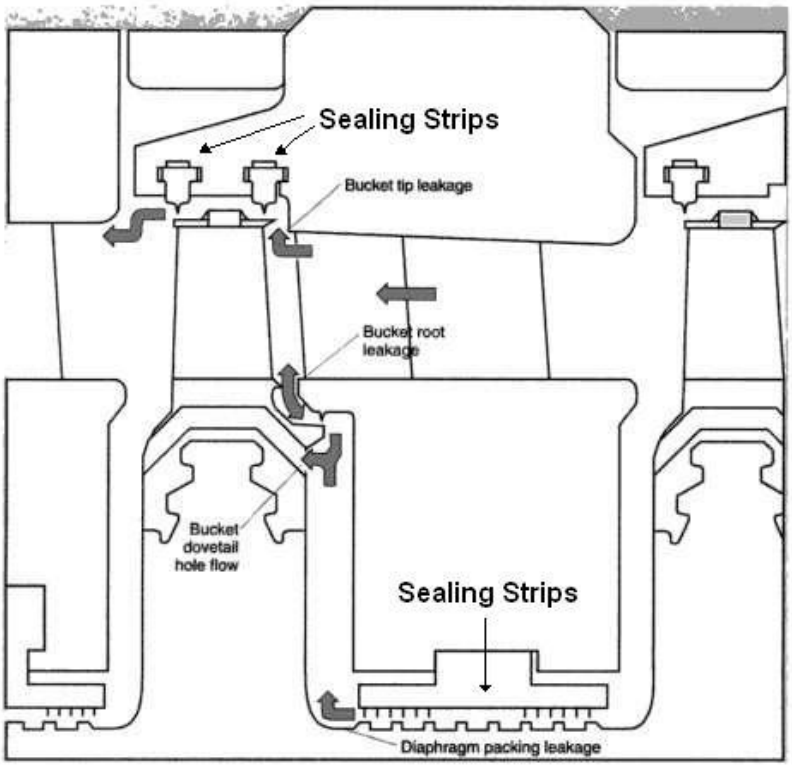



Figure 276

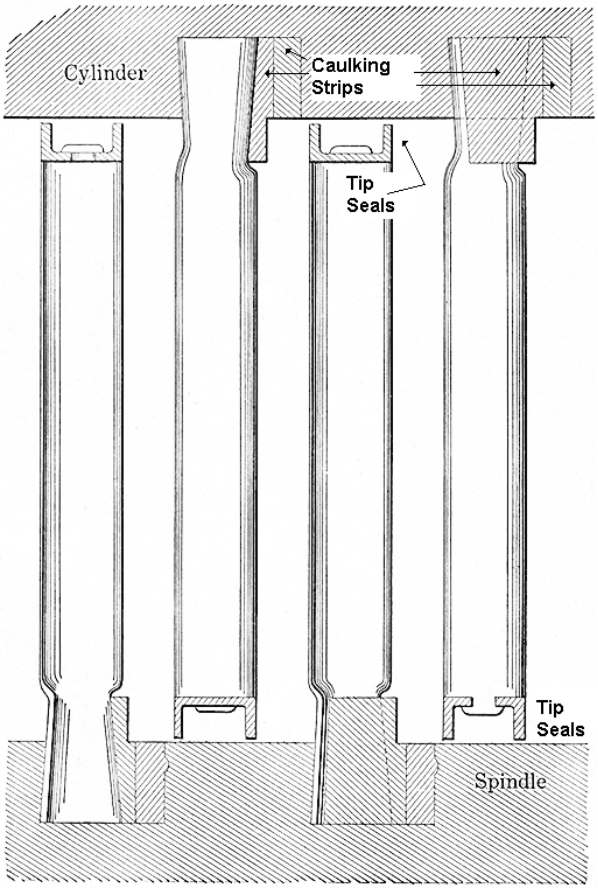



Figure 277. Sealing strips on the end of the shroud bands of the moving blades and stationary diaphragms

## 19. How thick are sealing strips?

Seal strips are often of chrome-iron alloy and may be approximately 0.01 inches thick at the sealing edge and 0.03 inches at the base. Where this design is feasible, the strips are rolled to shape and held in grooves by soft steel caulking strips.

*S&V page 50*

## 20. What is blade sealing?

Blade sealing is used principally in reaction stages to retard leakage across the blade tips, as there is a pressure difference across this type of blade. Sealing strips may be used on impulse turbines to help direct steam flow in high pressure stages and prevent leakage across the stage.

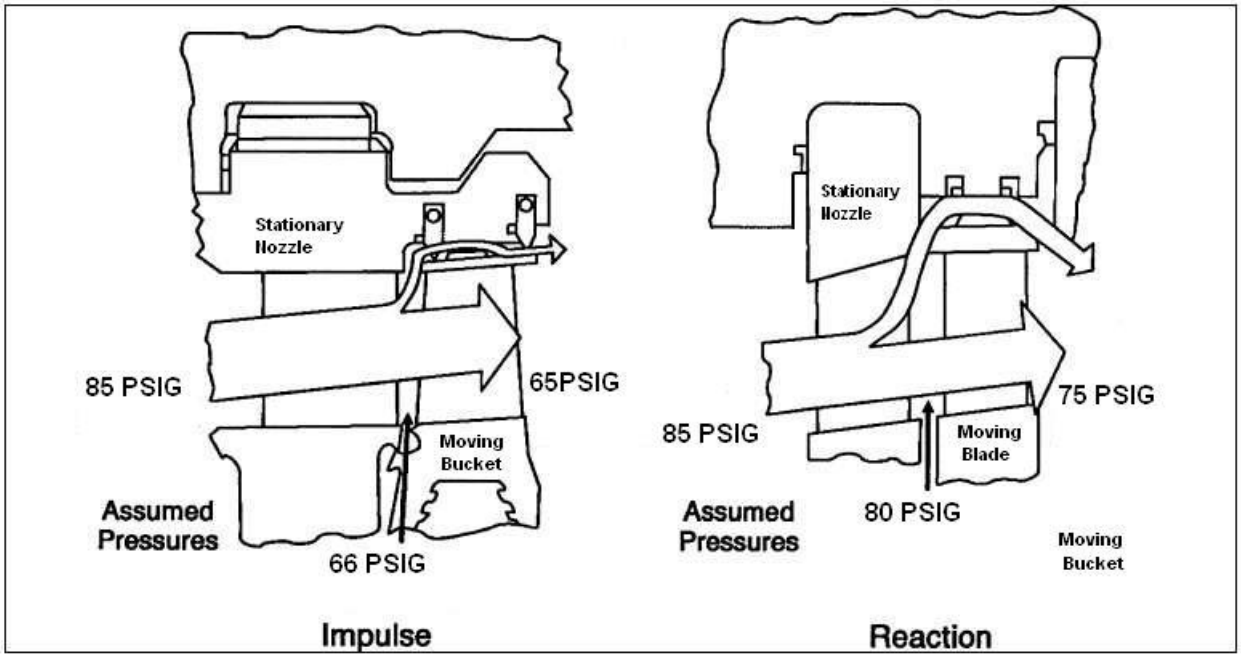



Figure 278. Tip leakage for impulse and reaction stages

## 21. What is meant by "tuning" the blades? Why is this done?

Unshrouded and unlashed blades will have natural frequencies under which they can assume detrimental vibrations. This is corrected by "tuning" the blades. Blades are tuned by changing their shape and weight so that their natural frequencies will not be within the operating range of the turbine.

## 22. What are squealer rings?

The tendency of the turbine wheels, when under normal load, is to move the shaft axially toward the generator and if for any reason the thrust bearing rings wear abnormally, and decrease the bucket clearance beyond the predetermined amount, the wheels will rub and cause damage. For the purpose of warning the engineer in case of any such excessive wear or damage to the thrust bearing rings, emergency or "squealer" rings are fitted.

*General Electric review, Volume 22 By General Electric Company page 240*

# Blade Problems

### 23. What is the most common cause of serious turbine outages?

The problem of turbine blade failures are the main cause of major steam turbine outages.

Factors in Blade Failures

A.) Stress-Corrosion Cracking 22%
B.) High-Cycle Fatigue 20%
C.) Corrosion-Fatigue Cracking 7%
D.) Temperature Creep Rupture 6%
E.) Low-Cycle Fatigue 5%
F.) Corrosion 4%
G.) Undetermined factors 36%
Total 100%

Besides, many damage mechanisms operate in combination of poor steam/water chemistry, certain blade design factors that vary from one turbine manufacture to other, and the way the system is operated contribute to these blade problems.

### 24. What is stress corrosion cracking, also known as SCC?

If the steam is contaminated with chlorides, it can lead to the occurrence of corrosion fatigue in turbine blades, blade roots and blade attachment areas. This is especially prevalent in the wet stages of the low-pressure turbine. Stress corrosion cracking has both a chemical and a physical (stress) component to its failure.

Stress corrosion cracking (SCC) is a progressive fracture mechanism in metals that is a result of the interaction of a corrodent and a sustained tensile stress. Structural failure due to SCC is often sudden and unpredictable, occurring after as little as a few hours of exposure, or after months or even years of satisfactory service. Metal components frequently experience SCC in the absence of any other obvious kinds of corrosive attack. Virtually all alloy systems are susceptible to SCC by a specific corrodent under a specific set of conditions. The specific environmental in a steam turbine would be the chemicals that came over with the boiler steam.

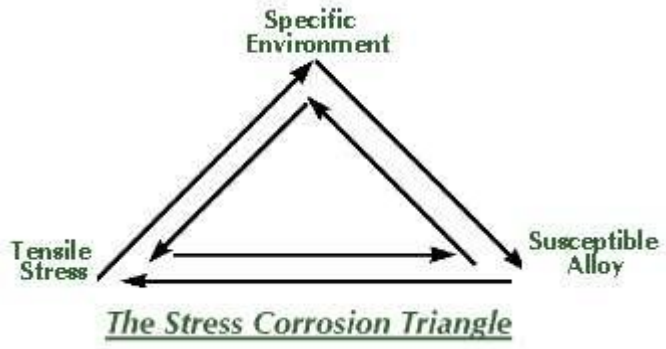



Figure 279.

## 25. What are the points of stress corrosion cracking attack?

Stress corrosion cracking attack predominates where corrodents deposit and build up i.e. in those blading areas where clean flowing steam cannot provide a washing effect.

**SCC FAILURE OF STEAM TURBINE BLADES**

**LOCATION :** C-8, Turbine # 81 Blade, Al-Jubail Plant

**CAUSE :** High stress at the pits of the trailing edges.

**MATERIAL :** 17- 4 PH Stainless Steel

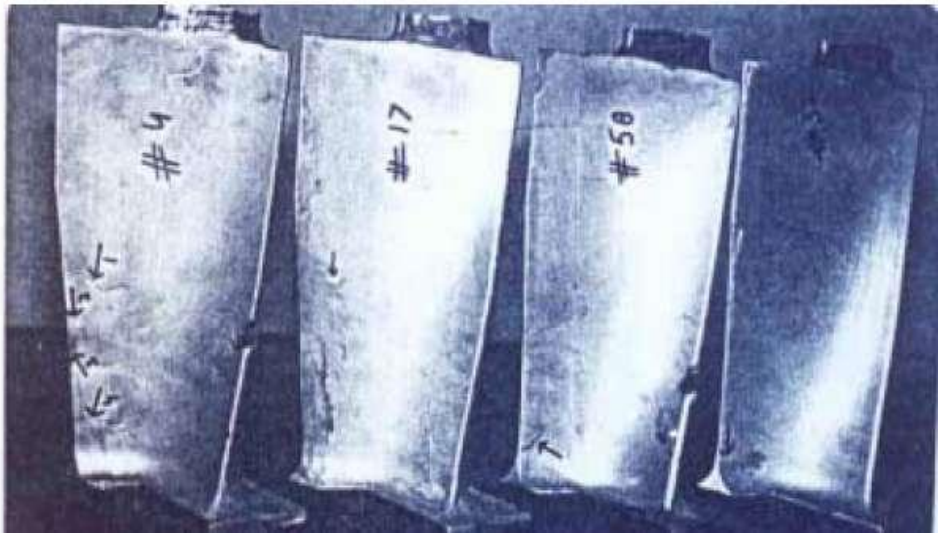



Figure 280.

Figure 281. Typical stress corrosion cracking

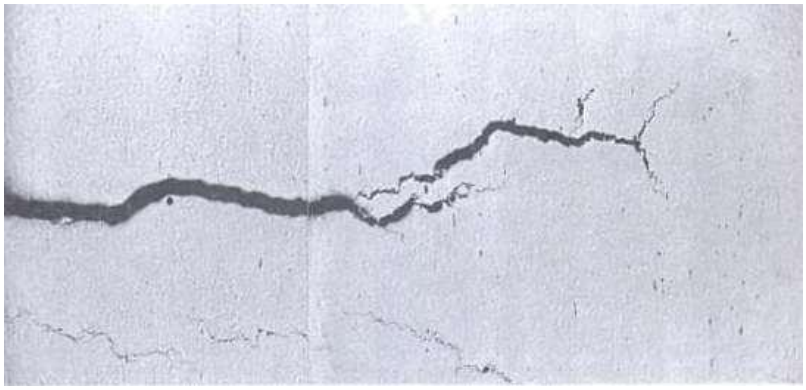


Figure 282. Stress Corrosion crack under the microscope

## 26. Where are some other areas where stress corrosion cracking can occur in blades?

Lacing wires

Lacing wire holes

Where satellite shields are brazed to the blade

Blade locking pin holes.

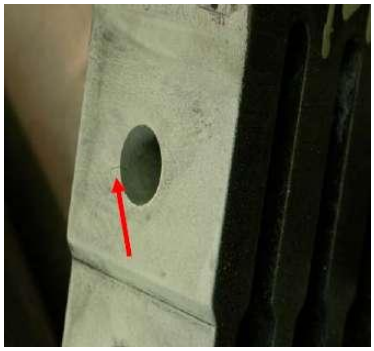


Figure 284. Crack at blade locking pin hole

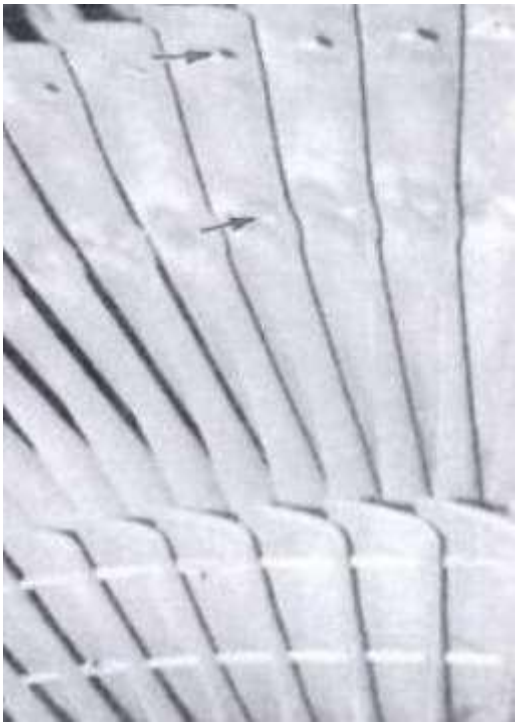


Figure 283. Arrows point to brazing fracture and failure of lacing wire. Pieces of the lashing wire caused damage throughout the downstream sections of the turbine

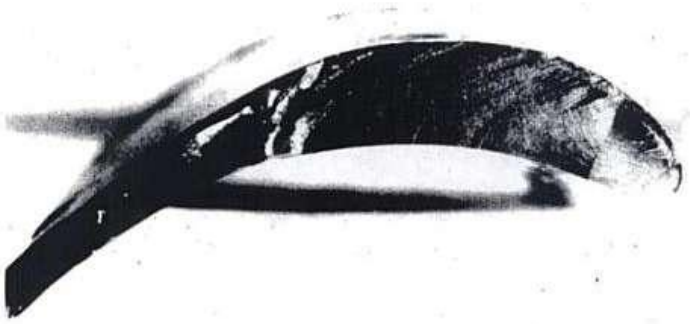


Figure 285. Fracture of the blade where the stellite shield was brazed onto the blade. The conchoidal fracture is also known as “beaching”

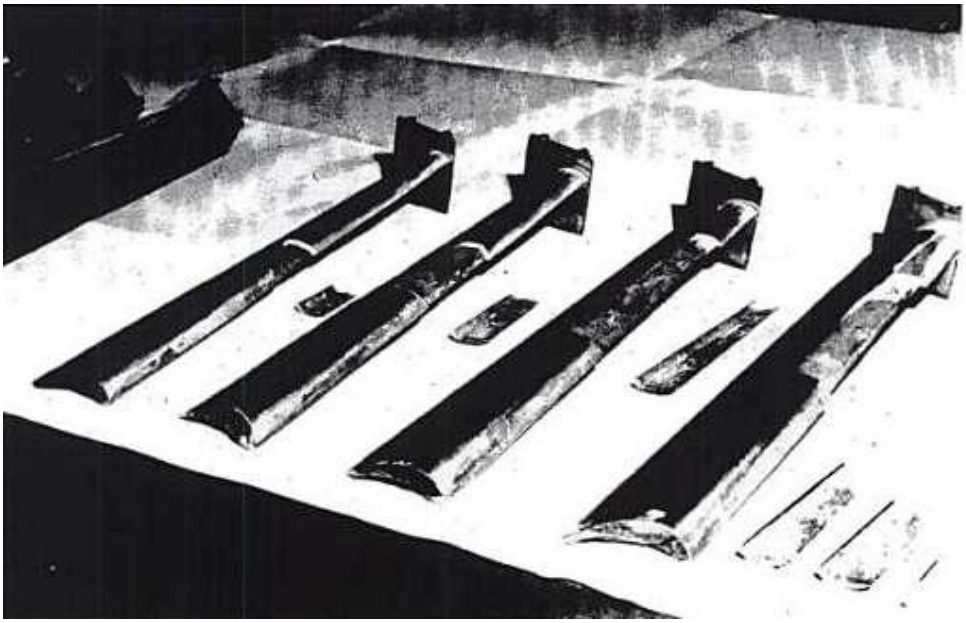


Figure 286. Delamination of the stellite shields from the blades due to thermal expansion differences between the brazing material and the stellite

## 27. Can damaged blades be repaired?

Not usually because the blade metallurgy has been affected by the exposure to the chloride attack. Replacement is the recommended procedure.

## 28. Why does stress corrosion cracking occur in nuclear turbines?

Steam turbines of nuclear power plants usually operate on wetter steam than those of fossil fueled power plants. Anywhere the steam becomes wet it can precipitate the impurities and create the conditions for stress-corrosion-cracking.

## 29. What is the solution to the problem of stress corrosion cracking /corrosion fatigue of steam turbine blades?

Improve the quality of the steel and the type of steel or titanium. Minimize the presence of chemicals in the steam through better water chemistry and tighter control of the limits set by the water treatment supplier.

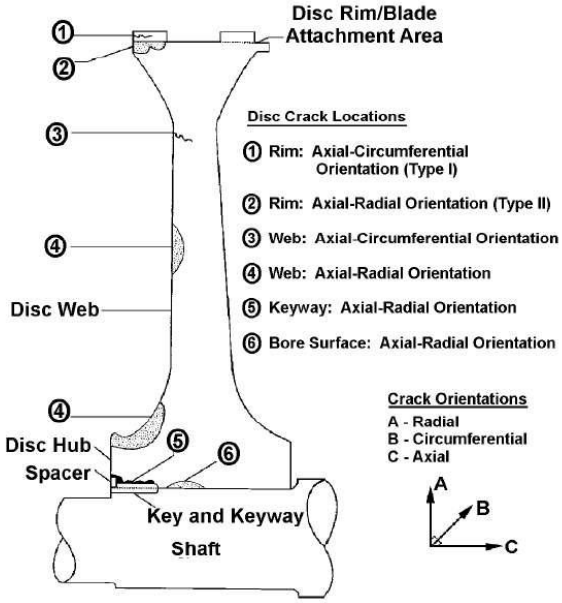



Figure 287.

Figure 289. Stress corrosion cracking caused the blade to crack and fly off

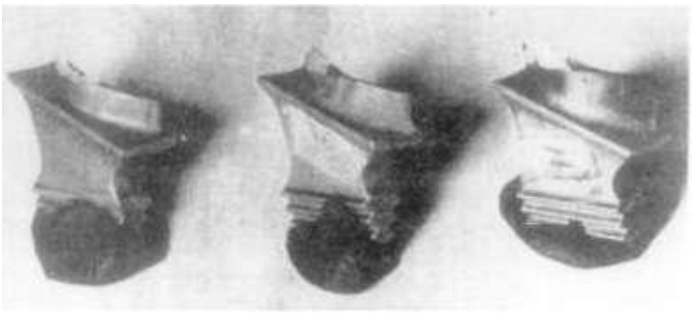


Figure 288. Turbine blades broken off near the root due to stress corrosion cracking

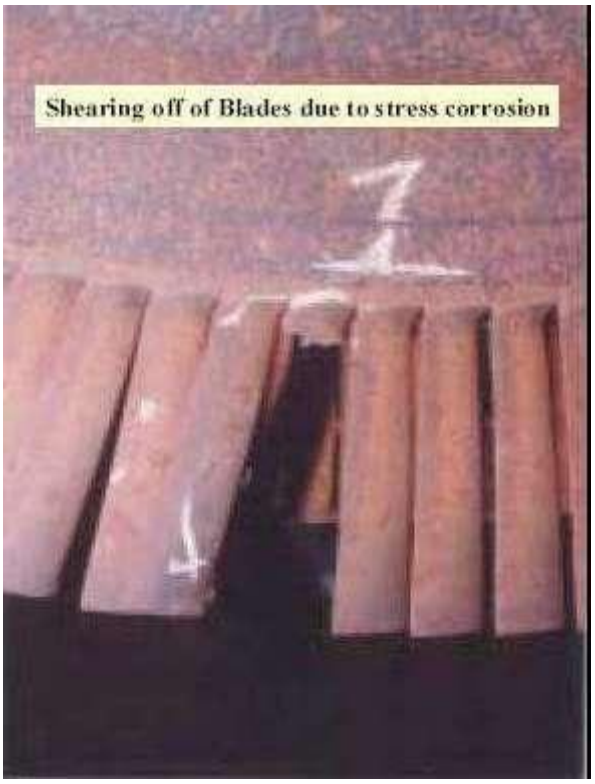
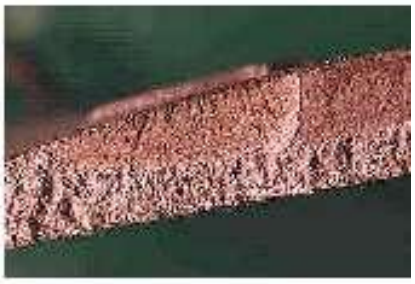



Figure 290.

Corrosion fatigue is fatigue in a corrosive environment. It is the mechanical degradation of a material under the joint action of corrosion and cyclic loading. Nearly all engineering structures experience some form of alternating stress and are exposed to harmful environments during their service life. The environment plays a significant role in the fatigue of high strength structural materials like steels, aluminum alloys and titanium alloys. Materials with high specific strength are being developed to meet the requirements of advancing technology. However, their usefulness depends to a large extent on the extent to which they resist corrosion fatigue. Effects of corrosive environments on fatigue behavior of metallic materials have been studied as early as 1930.



Fatigue cracking on an aluminium rotor blade

Figure 291.

Figure 292. Corrosion Fatigue Cracking

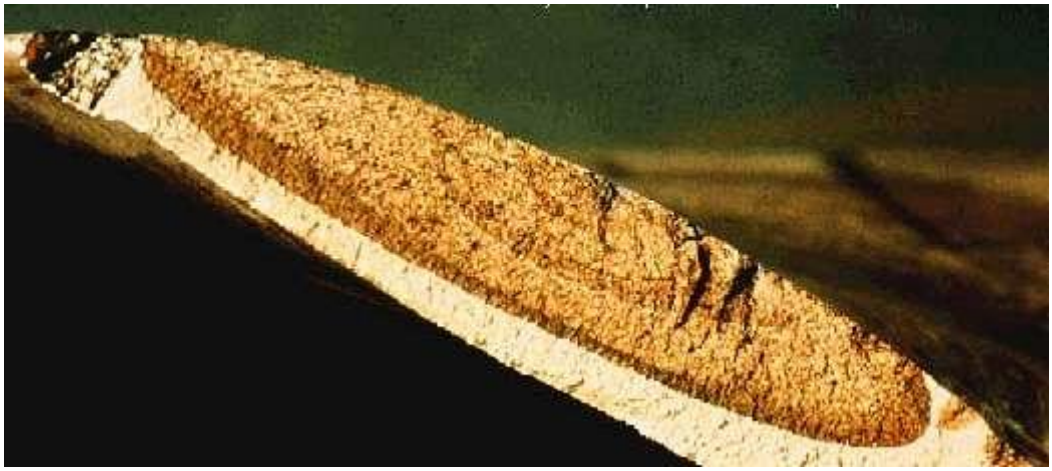


Figure 293. Corrosion Fatigue Cracking

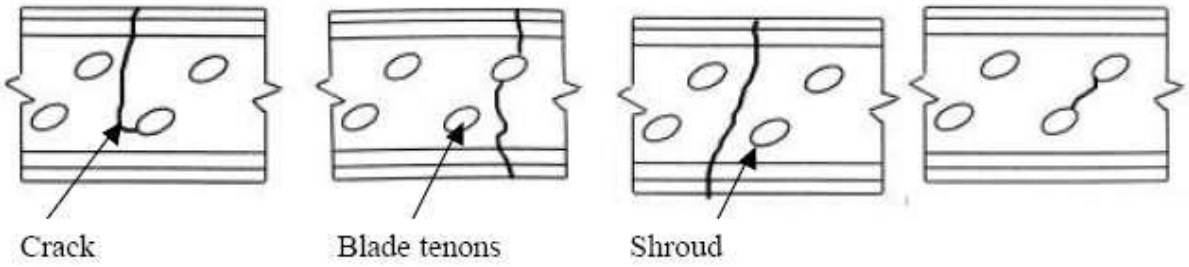



Figure 294. Corrosion fatigue cracking locations on shroud bands

## 30. What factors are responsible for turbine-blade failures?

In the high pressure cylinder, the turbine blades are mostly affected by:
A.) solid-particle erosion (SPE)
B.) high cycle fatigue,

**Solid particle erosion** of steam path surfaces is a major concern in steam turbines. This is mainly due to the formation of magnetite on the inside of boiler tubes. This builds up, spalls and travels along with the steam causing erosion in areas where steam velocities are the highest. The steam velocities are the highest in the high pressure sections of steam turbines.

A characteristic of solid particle erosion is that the amount of erosion is different on every blade.

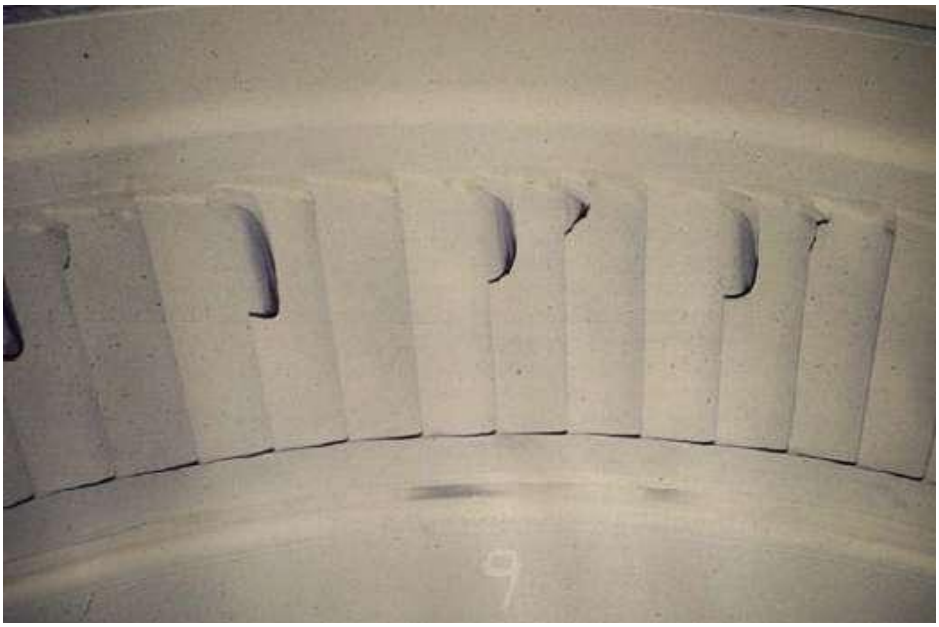


Figure 295. Solid particle erosion

Figure 296. Solid particle erosion

**High cycle fatigue**

In high cycle fatigue the endurance limit of a material after several million cycles is considered whereas in low cycle fatigue fracture after repeated loading is less than 10 cycles

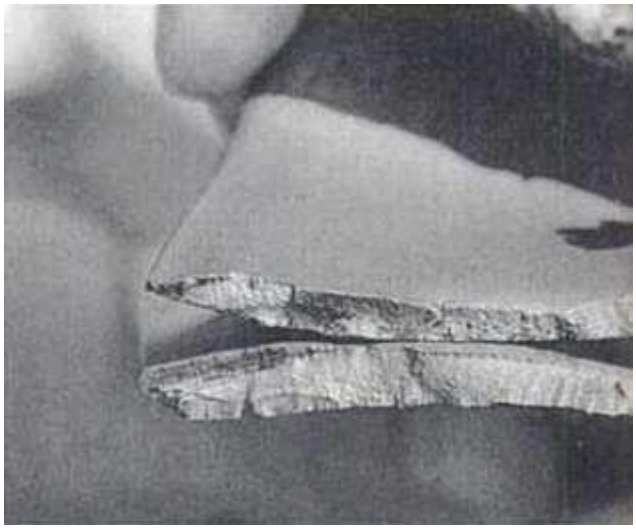


Figure 297. High cycle fatigue

Figure 298. The vertical striations are an indicator of high cycle fatigue

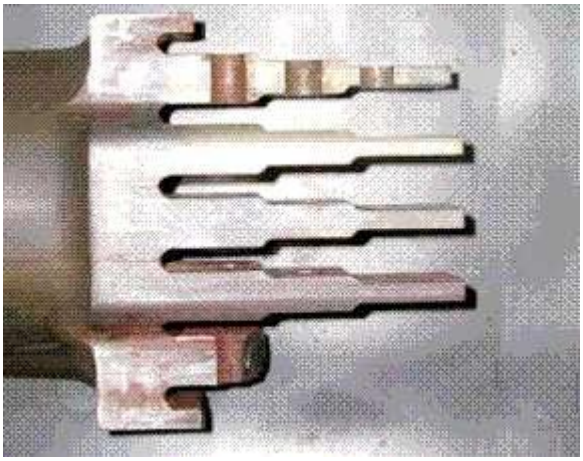


Figure 299. High cycle fatigue caused this finger of a turbine blade root to snap off

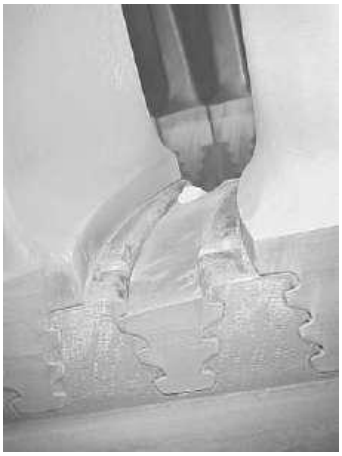


Figure 300. High cycle fatigue caused the entire blade to snap off at the root

Whereas in the last few stages of the low-pressure cylinder, the blade damage is mainly afflicted by:

A.) erosion
B.) corrosion
C.) stress/fatigue damage mechanism

According to the Electric Power Research Institute USA data, stress-corrosion cracking and fatigue are the chief causes of turbine-blade failures in utility industries.

## 31. What is to be done for erosion-induced damage on high-and low-pressure stage blading?

In such cases welding repair can be a good solution and this can be carried out during a normal maintenance outage without removing the blade. Using oxyacetylene torch, Stellite is generally deposited onto the damaged site. Following this, the weld is subjected to stress-relieving and re-profiling.

In case of erosion penetrating the erosion shield and extending to the base material, a filler material of consistent or identical composition of blade material is used.

In some cases use is made of Inconel alloy to build up the metal base. Therefore, using welding or brazing technique, a new shield can be attached to the blade. If brazing technique is followed, the rebuilt section is stress-relieved prior to the attachment of shield to it. If, on the other hand, the shield is attached by welding, then they are stress-relieved together.

Figure 301. Erosion of diaphragm blades

Figure 302. Installing Stellite Shielding with an oxy-acetylene torch

Erosion of turbine blades results in rough, uneven surfaces that alter steam flow paths. This reduces turbine efficiency and can also limit capacity. Erosion at the high-pressure end of a turbine is usually caused by solid particles (usually iron oxide) present in the steam. Iron oxide particles are present if they were not removed by steam blows during system start-up. They can also result from shedding of superheater or main steam header rust particles. It can also come from contaminated de-superheater spray water

Erosion of intermediate and low-pressure blades is usually caused by water in the steam. Operation below design inlet steam temperature or at low load can cause condensation in these stages, leading to erosion problems.

Carbon dioxide or other acidic chemicals present in the condensate can accelerate the damage. Some protection against erosion-corrosion can be provided by amines in the condensate, which neutralize the acidity and elevate the pH of the condensate.

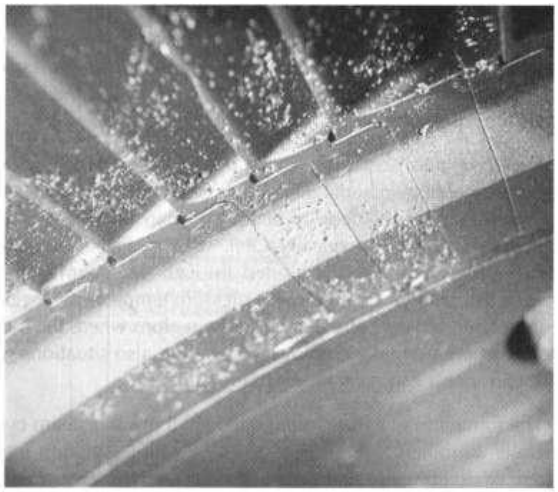


Figure 303. Corrosion pitting

corrosion fatigue and stress corrosion cracking of blades and disks are commonly associated with sulfides, chlorides, and caustic. The problems are most common in low-pressure sections of large power plant turbines, which are characterized by high stresses, crevices, and operating temperatures conducive to the condensation of concentrated solutions of steam contaminants. Problems also occur in high-pressure sections and smaller industrial-sized turbines, usually when substantial levels of steam contamination occur. These problems can be mitigated by designs that prevent crevices, lower stresses, and/or employ lower-strength materials. It is also important to avoid unnecessary stresses and to maintain high-purity steam during operation.

Figure 304. Sulfide contributed to stress corrosion cracking of this turbine disk.

## 32. What steps are taken to minimize damage from moisture impingement on steam turbine blades?

The following measures are employed at the design stage:
A.) Stellite inserts.
B.) Hardening of the base metal.
C.) Moisture-removal devices to combat impingement corrosion due to moisture.
D.) The drainage system should be redesigned. Larger drains are to be provided.
E.) More effective water-catchers are to be installed.
F.) Radial seals are to be eliminated to remove water before it can chance upon the blades.
G.) Nozzle trailing edges are to be thinned to promote the formation of smaller and less harmful droplets.

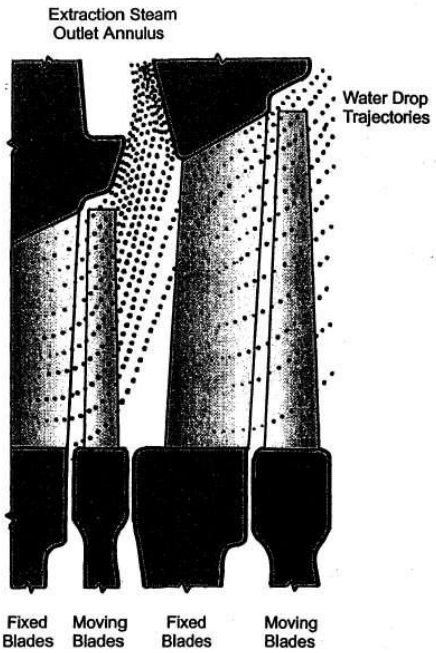



Figure 305. Water droplets in lower pressure stages

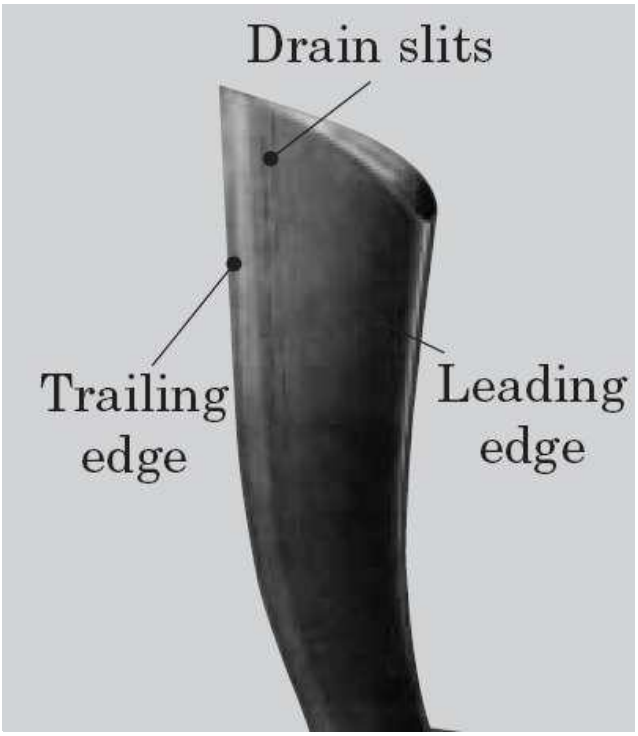



Figure 306. Drain slits incorporated into turbine blade design

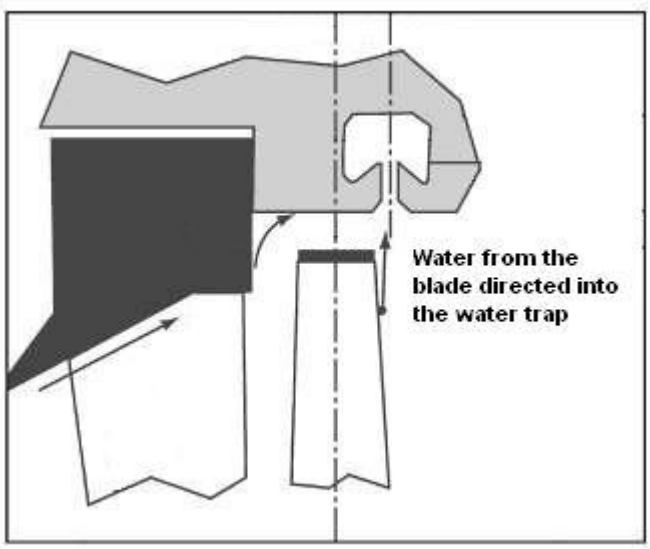



Figure 307. Water trap designed to direct water away from the turbine blades

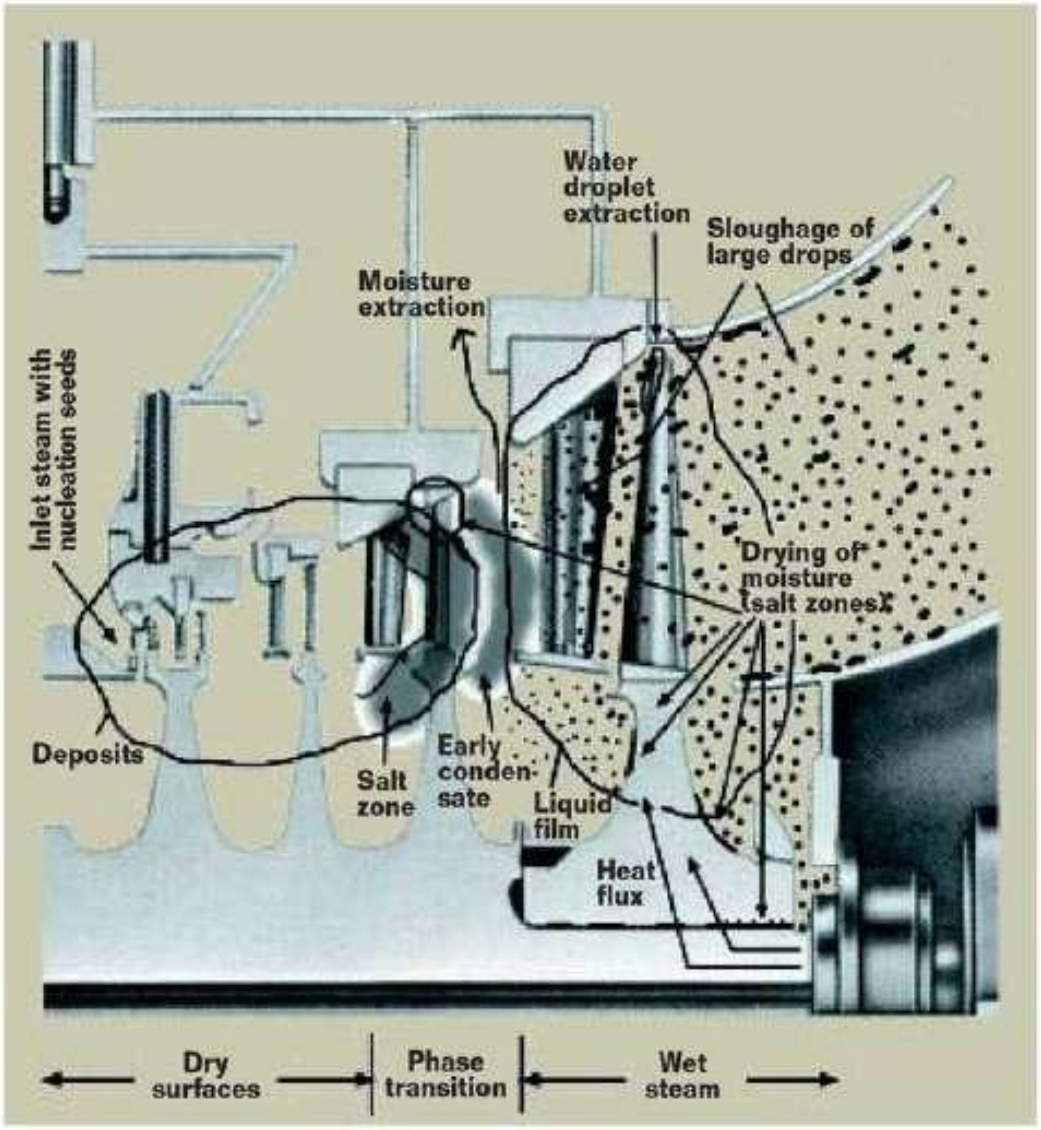



Figure 308. This drawing shows that as impure steam passes through the stages of the turbine and starts cooling, the impurities drop out in the form of salts, and the condensing steam starts impinging on the blades.

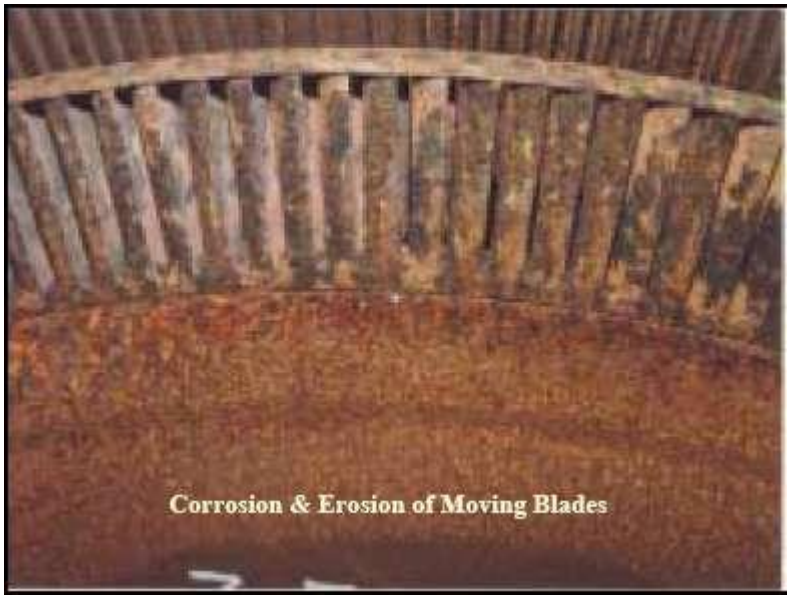



Figure 309.

## 33. At what points does corrosion fatigue does show up?

It attacks trailing edges, near the base of the foil and also the blade-root serration's in the wet stages of the low pressure cylinder.

## 34. What other parts of the steam turbine blades suffer from damage?

Blade roots.
Shroud band.

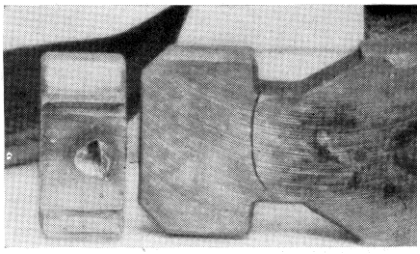


Figure 310. Broken root

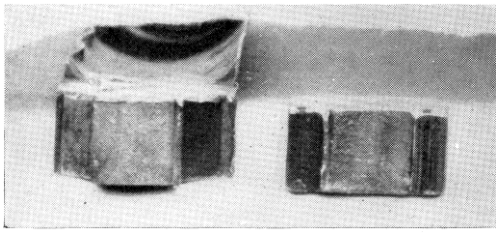


Figure 311. Broken roots

Figure 312. Dye penetrant reveals the crack on the steeple

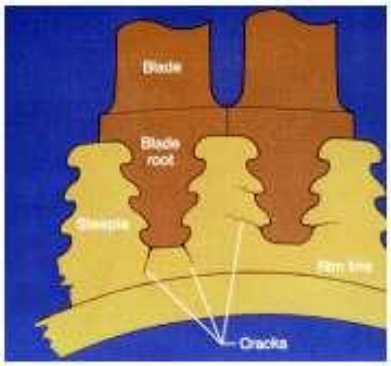



Figure 313. Stress corrosion cracking of steeples

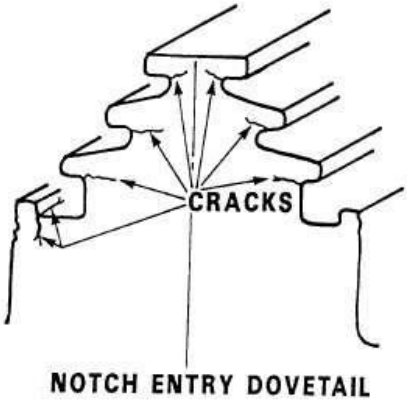



Figure 314.

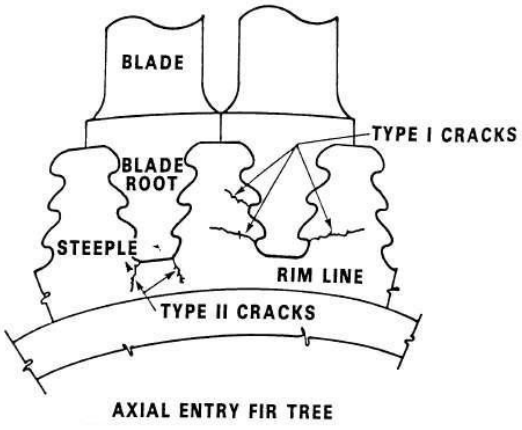



Figure 315.

## 35. Why do blade roots suffer from damage?

Fatigue is the common cause to the effect of blade root damage. Also a generic type of fault often assists this factor in design or manufacturer. Moreover, the root-fillet radii are subjected to a high degree of stress concentration with the effect that they crack relatively easily.

# Turbine Deposits and Cleaning

## 36. How does deposit formation on turbine blades affect turbine efficiency?

About 500 grams of deposits distributed more or less evenly all over the blading section can bring down turbine efficiency by 1%.

## 37. What type of deposits are formed on steam turbine blading?

A.) Water-soluble deposits.
B.) NaCl (sodium chloride or salt), $Na_2SO_4$, (sodium sulfate,) NaOH (sodium hydroxide), and $Na_3PO_4$ (trisodium phosphate)
C.) Water-insoluble deposits.
D.) $SiO_2$ silica.

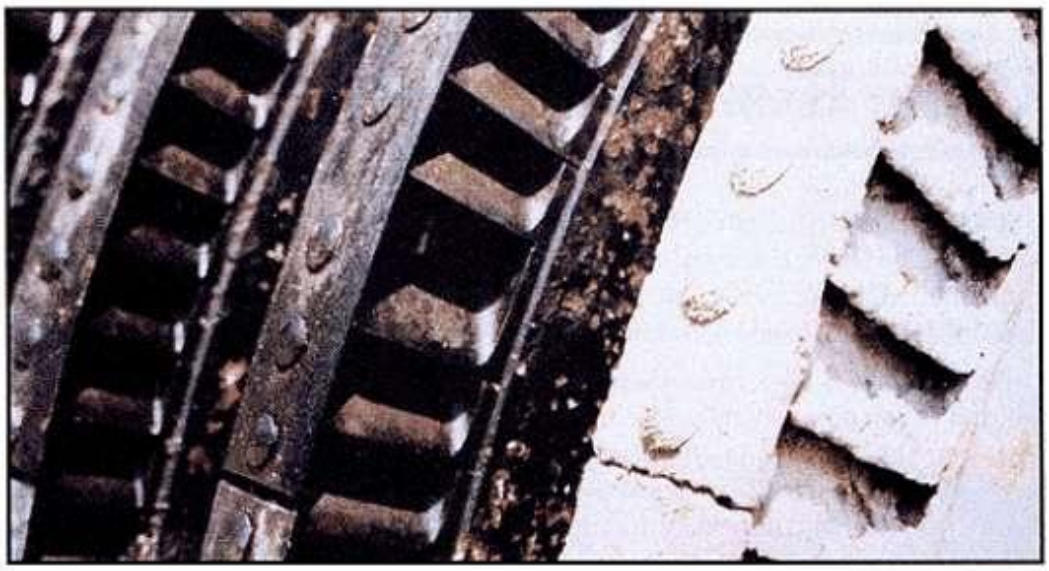


Figure 316. Salt deposits on last row of Rateau blading.

Figure 317. Deposits on turbine blading

## 38. What will solids carryover to a steam turbine do to stage pressure?

Stage pressures go up.

The most significant cause of efficiency degradation is deposits along the steam path as a result of boiler carryover. Deposits are not only detrimental to efficiency but they can also have a drastic effect on turbine reliability because of increased thrust loading and possibility of stress-corrosion cracking of components from high levels of caustic carryover. Boiler water chemistry, therefore, is of critical importance.

Water washing, detergent soaking, grit blasting and hand polishing are typical methods of removing deposits. Deposits can degrade performance by 1 to 15%.

*Woodruff & Lammers page 535*

The degree of fouling can be measured either by the percentage loss in capacity with a wide open governor valves or by the average percentage rise in stage pressures at a given load

*S%V page 134*

## 39. What are three ways in which steam passages in a turbine may be blocked?

Three ways are:

1) By carryover of solid matter in steam from the boiler.

2) By accumulation of condensate.

3) By foreign objects inadvertently left in the turbine or steam mains.

Figure 318. Proper practice is to keep an inventory of all tools, parts, and rags so that everything is counted and pieces like this washer are accounted for before closing the shell on the turbine.

## 40. What can be done about these blockages?

Three ways to correct these blockages are:

1. By means of washing and separation to eliminate the water droplets in steam leaving the boiler. Also, clean the turbine periodically.

2. When the turbine is started up, leave all drain lines open a sufficient length of time.

3. Inspect thoroughly all equipment before finally assembling it.

## 41. How do turbine depositions affect the turbine?

Economic Effect:

a. reduction in turbine output
b. decrease in efficiency requiring higher steam consumption.

Effect of Overloading and Decreasing Reliability in Operation:

a. Pressure characteristic in the turbine gets disturbed with the result that thrust and overloading of thrust bearing increases.
b. Blades are subjected to higher bending stresses.
c. Natural vibrations of the blading are affected.
d. Vibration due to uneven deposition on turbine blading.
e. Valve jamming due to deposits on valve stems.

Corrosion Effect:

a. Fatigue corrosion.
b. Pitting corrosion.
c. Stress corrosion

## 42. What is the cause of turbine deposits?

The turbine deposits are steam-born foreign matters settled on turbine blades. Substances dissolved in the boiler feedwater transfer partly from the water to steam, during the process of evaporation. They get dissolved in the steam and are carried into the steam turbine.

## 43. Where do water-soluble deposits prevail?

In the high-and intermediate-pressure sections of steam turbines.

## 44. What is "turbine fouling"? How is it measured? How is it corrected?

Turbine fouling is fouling of the nozzles, blades, and valves by chemical deposits carried over from boiler drum water. It is measured by efficiency loss. It is corrected by adjustment of feed-water treatment and internally cleaning the turbine.

## 45. How can the deposits be removed?

Water soluble deposits may be washed off with condensate or wet steam.

Water insoluble deposits are removed mechanically after dismantling the turbine.

Experience shows that water soluble deposits are embedded in layers of water-insoluble deposits. And when the washing process is carried out, water soluble parts of the deposit dissolve away leaving a loose, friable skeleton of water-insoluble deposits which then break loose and wash away.

## 46. How do you clean deposits from turbine blading?

Cleaning method depends on the chemical nature of the deposits. Frequency of washing is a matter of economics.

The most common method of cleaning turbines is the saturated steam wash by water injection. With this method feedwater is sprayed into the steam line ahead of the throttle valve. The turbine is run at 20 to 25% normal speed. The water is sprayed until the steam contains several percent of moisture. The flow then continues until the condensate being thrown overboard shows complete absence of the chemical being washed out of the turbine.

Deposits can also be removed after disassembly by acid cleaning or sand or flyash blasting.

*S&V page 132*

*D.E.S.C. Turbine Operation page 14*

In air blasting with a blasting medium, the medium should be harder than the deposit but softer than the blade metal. Pulverized corncobs or walnut shells have been successfully used

*Ted Antil Chief Engineer IMPC  Paper Mill*

Figure 319. Blasting deposits off turbine blading

Figure 320. Blasting with proper respiratory gear in use

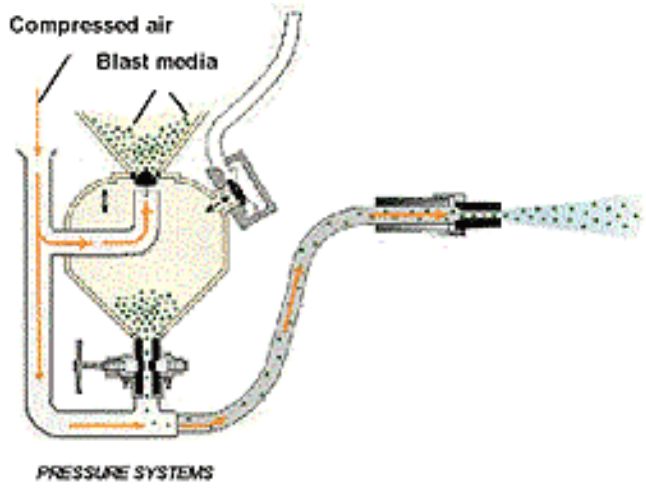



Figure 321. Diagram of blasting gear

Figure 322. Blasting turbine blading clean

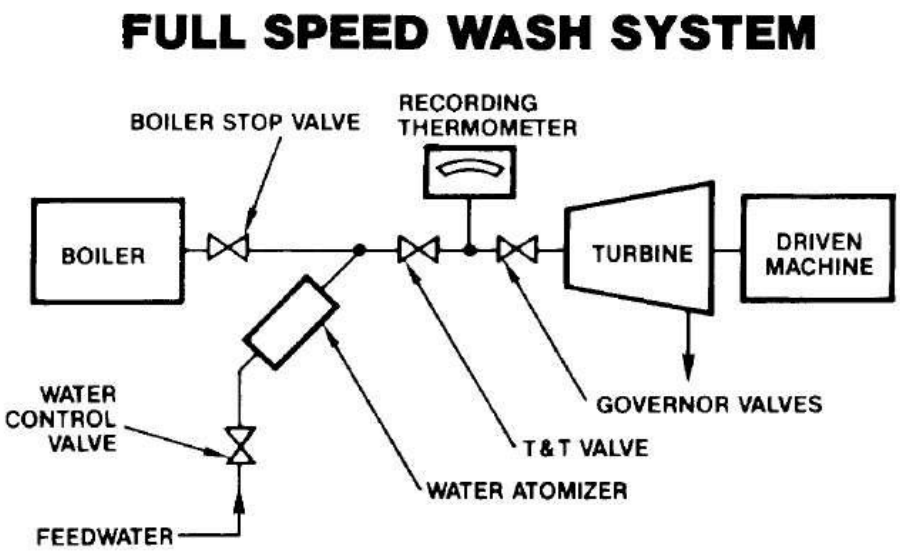



Figure 323. Diagram shows a turbine wash with feedwater

## 47. How is the washing of turbine blades carried out with the condensate?

The washing is carried out with the condensate at 212°F. The turbine is cooled or heated up to 212°F and filled with the condensate via a turbine drain. The rotor is turned or barred by hand and the condensate is drained after 2 to 4 hours. It is then again filled with the condensate at 212°F (but up to the rotor center-level), the rotor is rotated and the condensate is drained after sometime. This process is repeated several times.

## 48. How is turbine blade washing with wet steam carried out?

Wet steam produced usually by injecting cold condensate into the superheated steam, is introduced to the turbine which is kept on running at about 20% of nominal speed.

For a backpressure turbine the exhaust steam is let out into the open air through a gate valve. For a condensing turbine, the vacuum pump is kept out of service while cooling water is running, with the effect that the entering cooling steam is condensed. The condensate is then drained. The washing steam condition is gradually adjusted to a final wetness of 0.9 to 0.95.

Note: it is important not to change washing steam temperature by 10°C/min (50° F/min), and to keep all turbine cylinder drains open.

## 49. How fast does a turbine rotate when washing with wet steam?

The turbine is run at 20 to 25 per cent normal speed and the feed water is carefully controlled to reduce the steam temperature at a uniform rate not greater than 100 F per hour. The feed-water injection rate is continued until the steam entering the turbine contains several per cent moisture.

*S&V page 132*

## 50. What do you clean clogged turbine nozzles with?

The most frequent cause of loss of efficiency is fouling of nozzles blades and valves by chemical deposits carried over from the boiler drum water. Adjustment of feedwater treatment methods should be the first thing investigated, whenever this condition arises.

The most common method of removal of deposits is the saturated steam wash by water injection method.

*S&V pages 131-133*

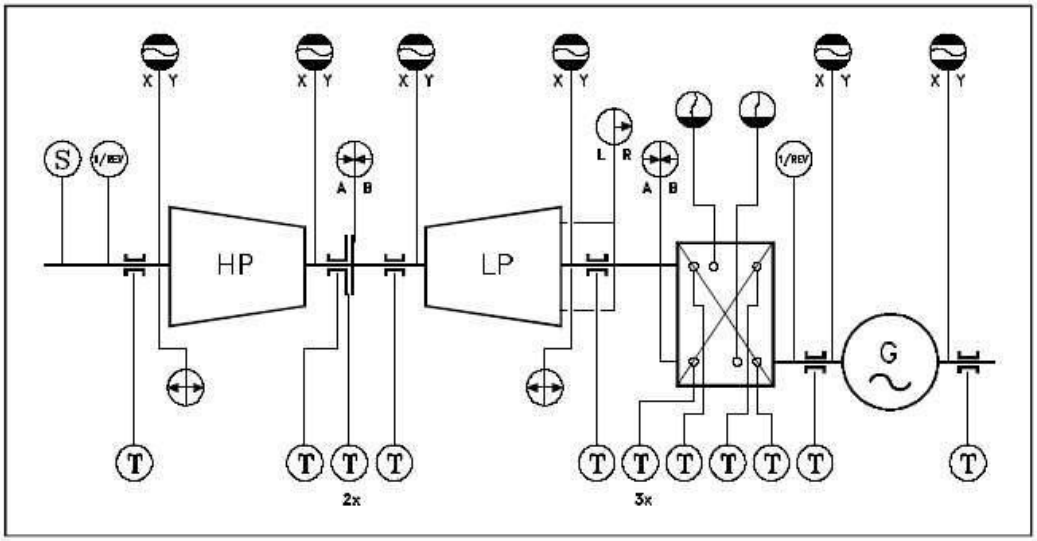
## 51. How can the detection of deposits in a turbine be made during operation?

Pressure monitoring

Internal efficiency monitoring

Monitoring exhaust steam temperature

Monitoring specific steam consumption




Schematic of a medium-sized industrial turbine showing measurement points and types

Figure 324.

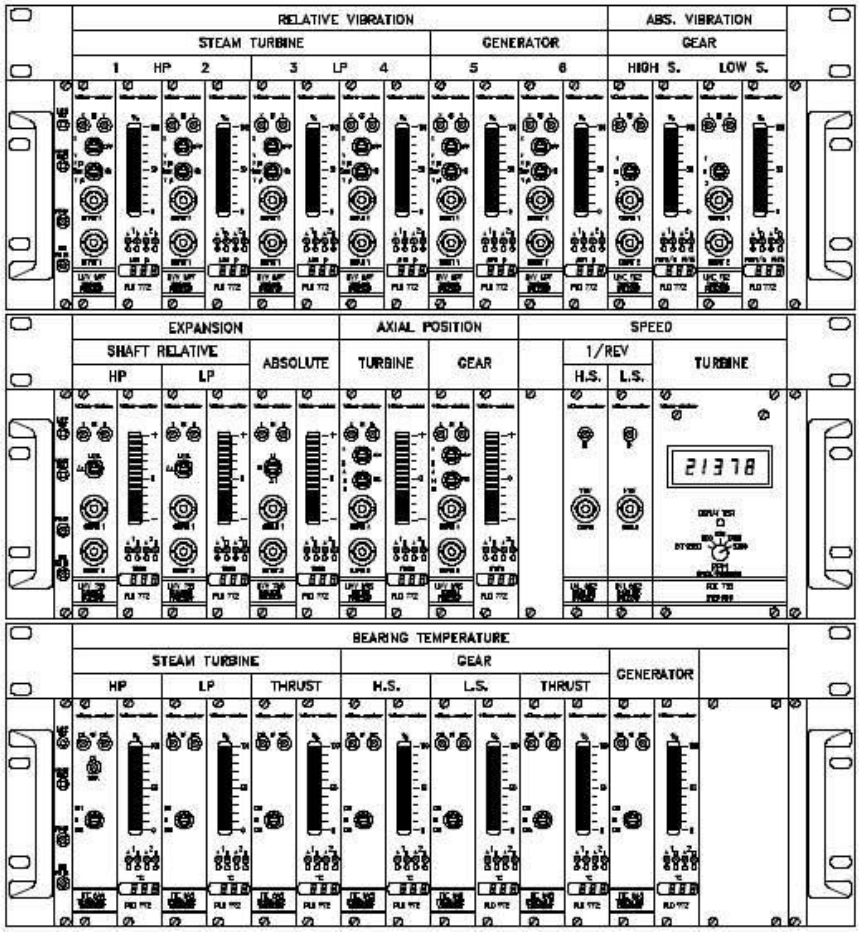



Figure 325. Monitoring equipment is attached to the sensors of the diagram above to monitor the turbine during operation and note anything unusual on the hourly log sheets

## 52. How does the internal efficiency monitoring lead to the detection of turbine deposits?

Process heat drop.

Adiabatic heat drop.

The process heat drop and adiabatic heat drop are obtained from a Mollier-Chart for the corresponding values of steam parameters - pressure and temperature - at initial and final conditions.

## 53. How to prevent turbine deposition?

By upgrading the quality of steam. That is by ensuring proper:

Boiler feedwater quality.

Steam boiler model.

Boiler design.

Boiler operation.

## 54. What happens when "stall flutter" occurs?

This problem is encountered when operating limits are exceeded. When turbine exhaust pressure exceeds the value what the manufacturer has recommended, stall flutter induces stress in the blades

Harmonic excitation seen by the moving blades is a fluctuating steam flow field at the rotational speed that creates differing harmonics. By design practice all the long blades are tuned so as to avoid resonance due to harmonic excitation. However the turbine blades normally experience random excitation. Such excitation is primarily due to temporary unsteadiness of the flow over the stationary blade. The third type is self-excitation, which primarily includes stall flutter that can occur in any of the lower modes of the blade. Under the right conditions, the blades “organize themselves” into a systematic self-excited vibration. A self excited vibration does not need external excitation; instead, the excitation frequency is internally generated. For example, a blade, which is no longer in equilibrium will vibrate back to equilibrium at its natural frequency. This vibration may modulate the steam flow so that the resulting dynamic forces act to sustain the vibration. The blade then vibrates in a self-excited manner. The vibration is maintained right at the natural frequency. Such a vibration associated with turbine blade is called flutter and is a well-recognized source of fatigue in the blade. Sudden changes in the flow path and steam extraction have been observed to initiate flutter in the blade. Another well recognized last blade vibration is the stall flutter. During operation at very low load and high exhaust pressure, stall flutter occurs in the last stage blades of a low-pressure turbine, which result in severe vibratory stresses.

Aeroelastic instability, which occurs at extreme conditions either in the region of low steam flow or at high condenser pressure, produces significant flow separation at the blade hub, resulting in stall flutter and buffeting of the blades. The use of titanium alloy blades with reduced damping properties makes a change in blade manufacturing from free-standing to interlocked construction an unavoidable necessity.

During turbine operation, the blade elastically untwists due to centrifugal forces, causing vibration. Blades with integral shroud and tie-bosses situated at 70% of the blade height exhibit two to three times less vibrational stress than do free-standing blades.

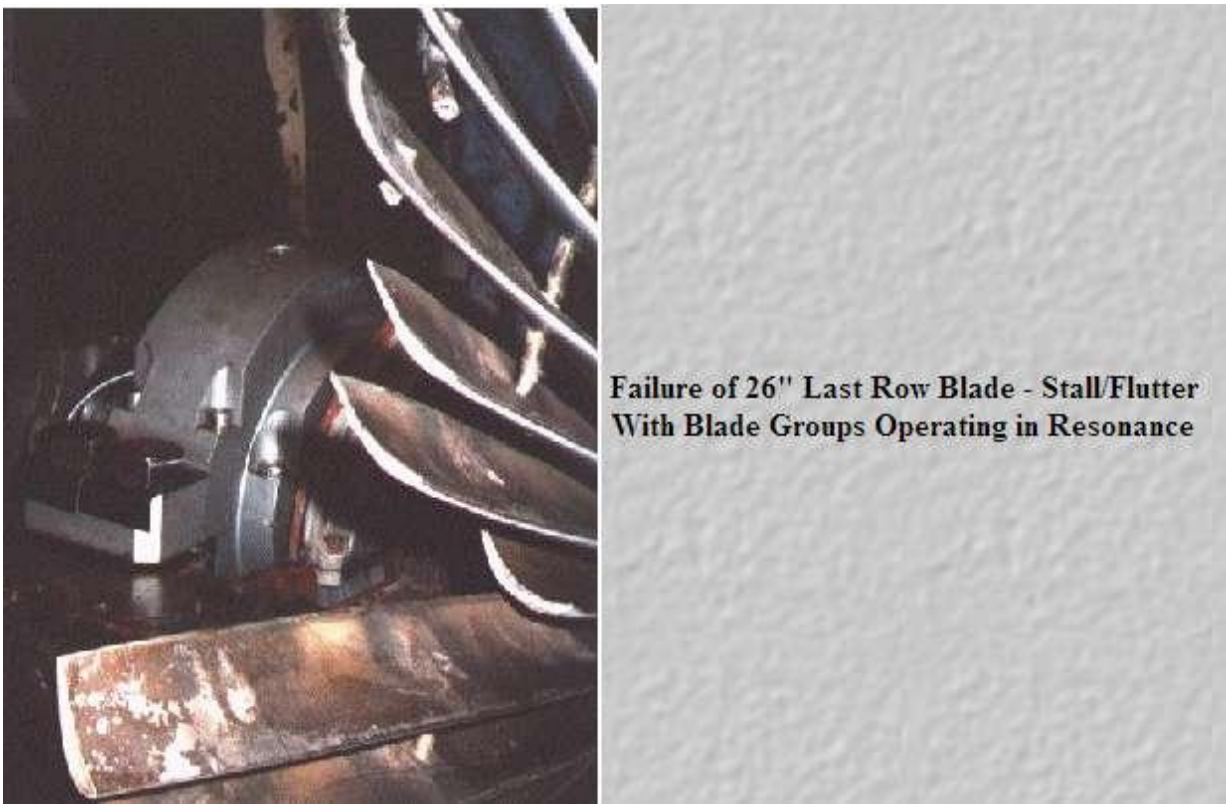



Figure 326. Results of stall flutter.

# Chapter 6 Lacing Wire

## What is lacing wire used for in a reaction turbine?

It is used to improve the rigidity of the longer blades in the latter stages of a turbine. Some manufacturers make a practice of drilling a hole through the blade, about midway in its length. A wire is passed through the holes in these blades to form a stiffening ring. Where the wire passes through the blades the wire and the blade are joined by welding. This type of construction is called "lacing", meaning that lacing wire has been used to stiffen the blades. This wire is often a quarter of an inch or larger in diameter.

*D.E.S.C. Turbines. page 23*

Figure 327. This turbine uses three rows of large lacing wire

Figure 328. Lacing wire to stiffen the blades

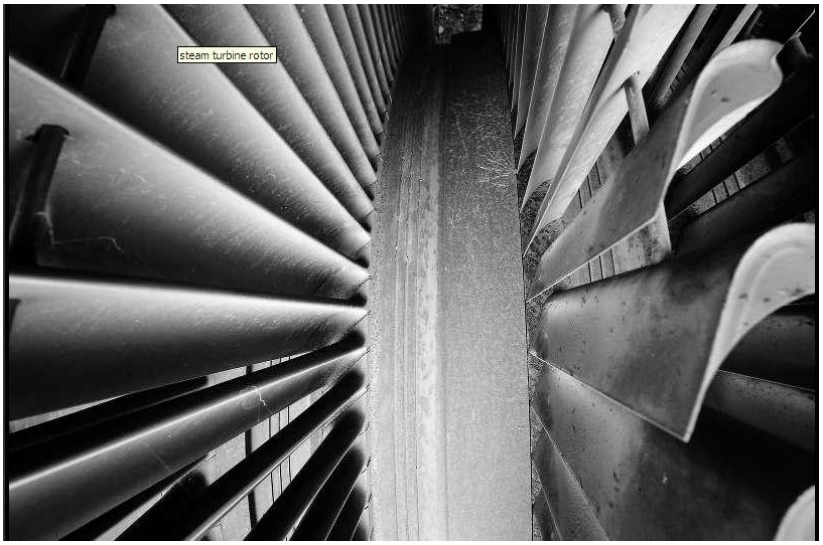



Figure 329. Looking down at the rotor with lacing wire through the blades

Figure 330. Lacing wire through reinforced areas of the blades

## What is to be done in case of cracks originating at the lacing-wire holes?

These are to be weld-repaired. However the following factors must be considered:
(a) The length of the crack that appears on the pressure and/or suction face.
(b) Whether the cracks propagate towards inlet end, discharge end and or both.

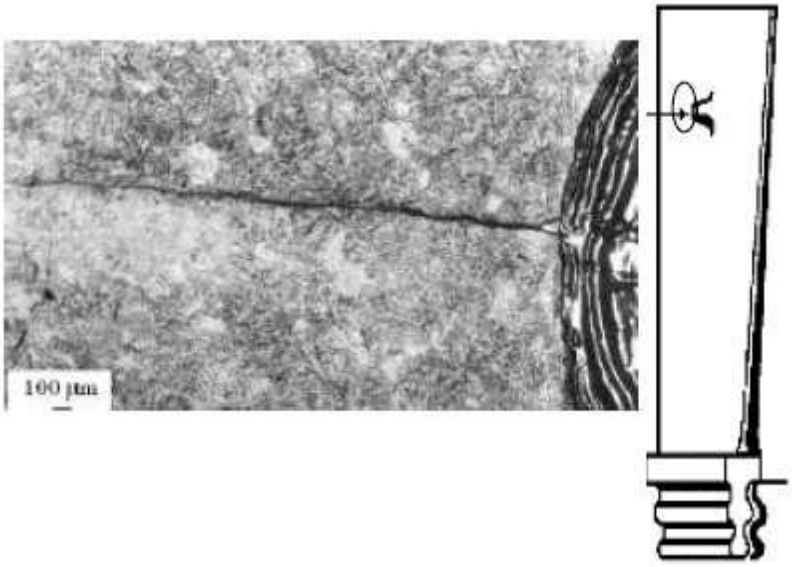



Figure 331. Crack at lacing wire hole

## In how many patterns are tie wires used?

In one design, tie wire is passed through the blade vane. In another design, an integral stub is joined by welding/brazing

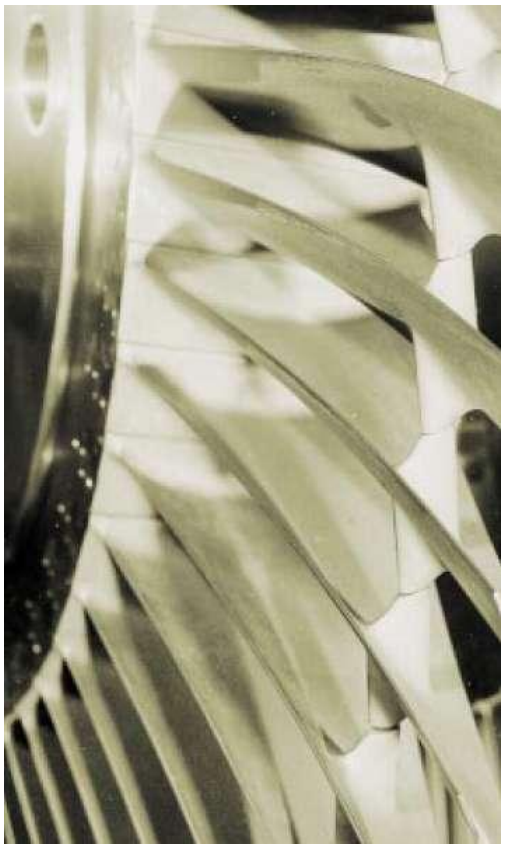


Figure 332. Integral casting forms stiffening ribs in place of lacing wire

# Chapter 7 Diaphragms, Discs, and Wheels

## 1. What is a diaphragm?

Partitions between pressure stages in a turbine's casing are called diaphragms. They hold the vane-shaped nozzles and seals between the stages. Usually labyrinth-type seals are used. One-half of the diaphragm is fitted into the top of the casing, the other half into the bottom.

Figure 333. Impulse Diaphragm

Figure 334. Reaction Diaphragm

## 2. What are diaphragms made from?

Diaphragms, when cast in halves, must be made sufficiently strong and rigid to avoid undue deformations due to temperature and pressure differences. They usually are dished towards the high-pressure side to increase strength. Diaphragms in large machines are made of cast steel, fitting on centralizing supports in turned circumferential slots in the casing. These diaphragms sometimes carry a shoulder projecting almost to the adjoining diaphragms and just outside the blade ring. If the disc fails, the flying pieces must rupture this heavy steel shoulder before piercing the casing.

*Kents 11th Edition. page8-50*

Figure 335. Impulse Diaphragms

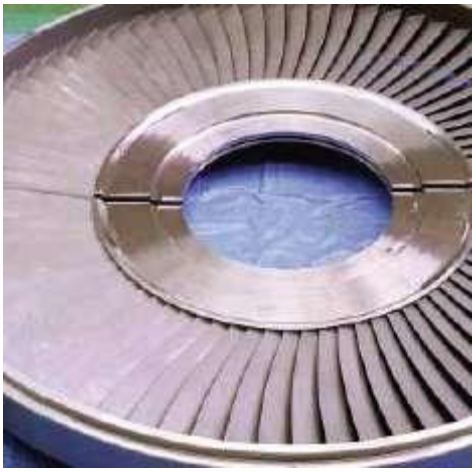
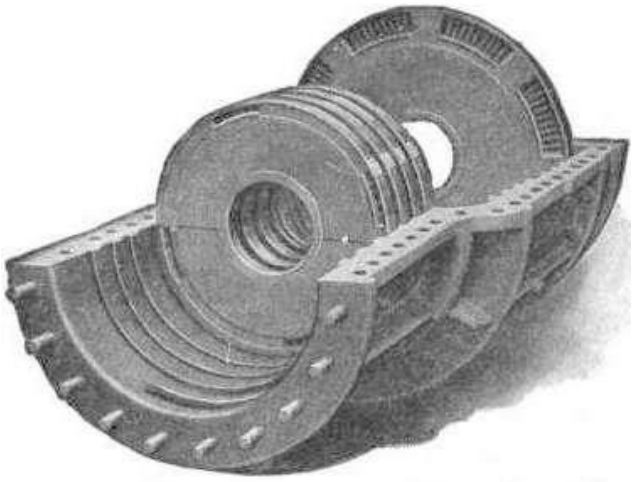


Figure 336. Reaction Diaphragms

### 3. What are diaphragms, as pertaining to turbine nozzles? How are they made and assembled?

Diaphragms are stationary wheels which have the nozzles built into them. They are split horizontally at the center line and upper and lower halves are fitted into grooves in the turbine casing.

Figure 337. Impulse Diaphragms



Lower Half of Turbine Casing Showing Diaphragms in Place, and the Circumferential Grooves for Holding Them

Figure 338. Diaphragms in lower half of casing

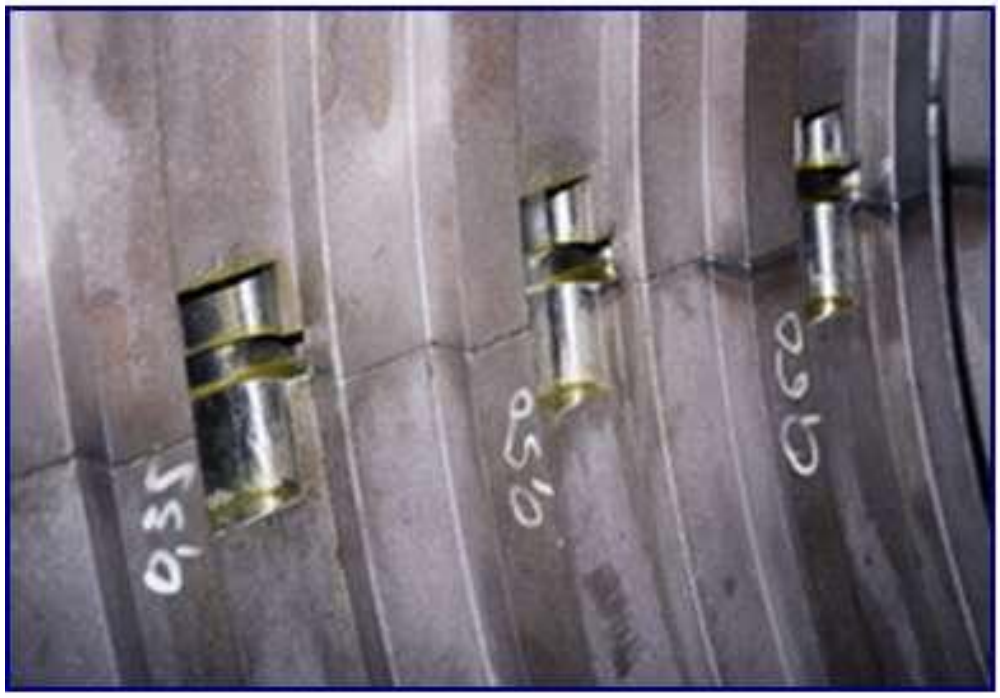


Figure 339. Circumferential grooves in turbine casing for holding diaphragms

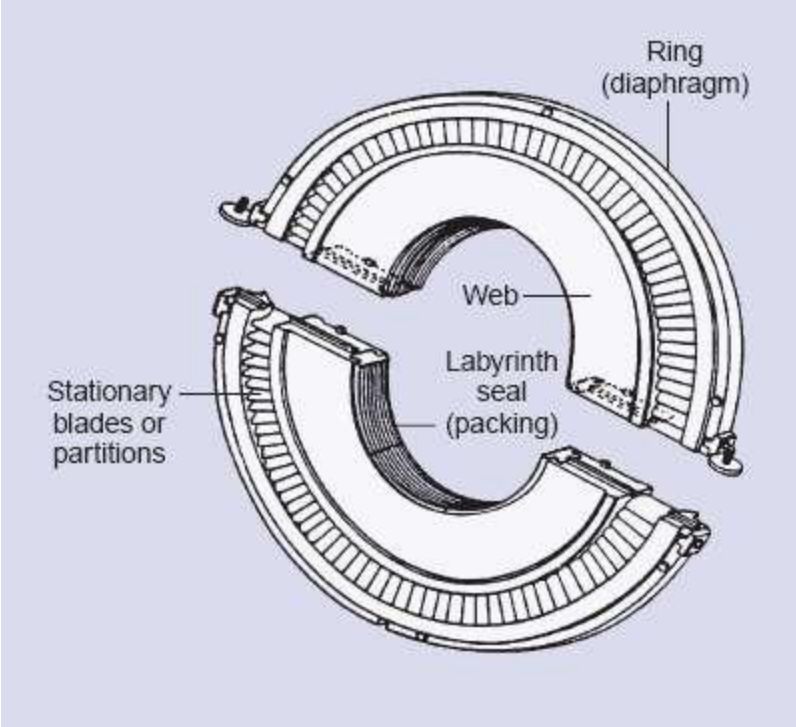



Figure 340. The labyrinth packing helps stop the steam from leaking between the rotor and the diaphragm

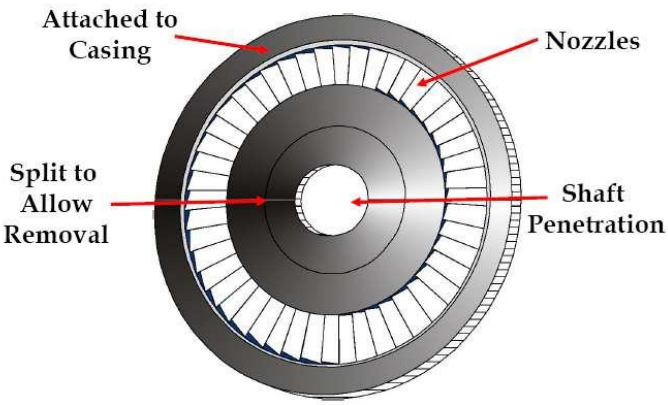



Figure 341. Diagram of diaphragm construction

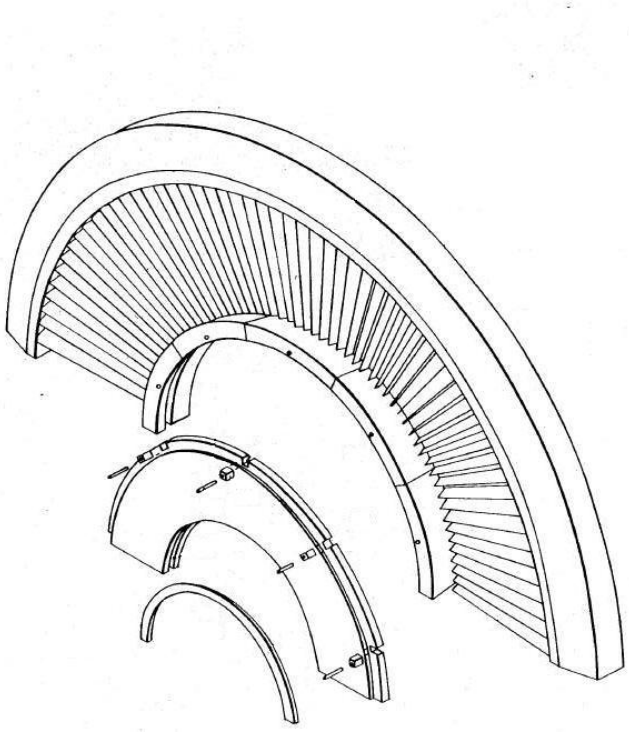


Figure 342. Diaphragm showing how the web is attached to the diaphragm

Figure 343. Removing the diaphragms from a large turbine

Figure 344. Diaphragms are removed and placed in a rack during overhaul. Note tongue and groove at diaphragm centerline.

## 4. How do you align the diaphragms and the casing so that the rotor can turn freely without rubbing?

By laser alignment of the diaphragms around the center of the rotor. The rotor must be removed and the center point found. The diaphragms are attached to the inner casing. By replacing the casing without the rotor, measurements can be taken and the diaphragms shimmed until the casing and the rotor are in perfect alignment. Then the casing is taken back off and the rotor is replaced.

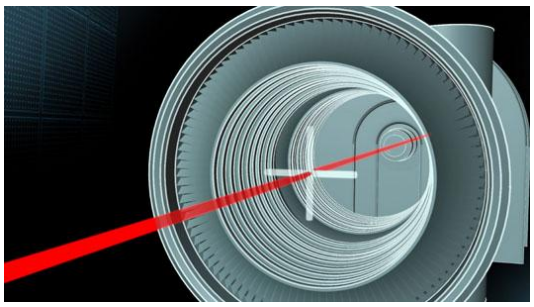


Figure 345. Laser alignment diagram

Figure 346. Technician aligning the diaphragms. Notice the laser dot on the technicians arm

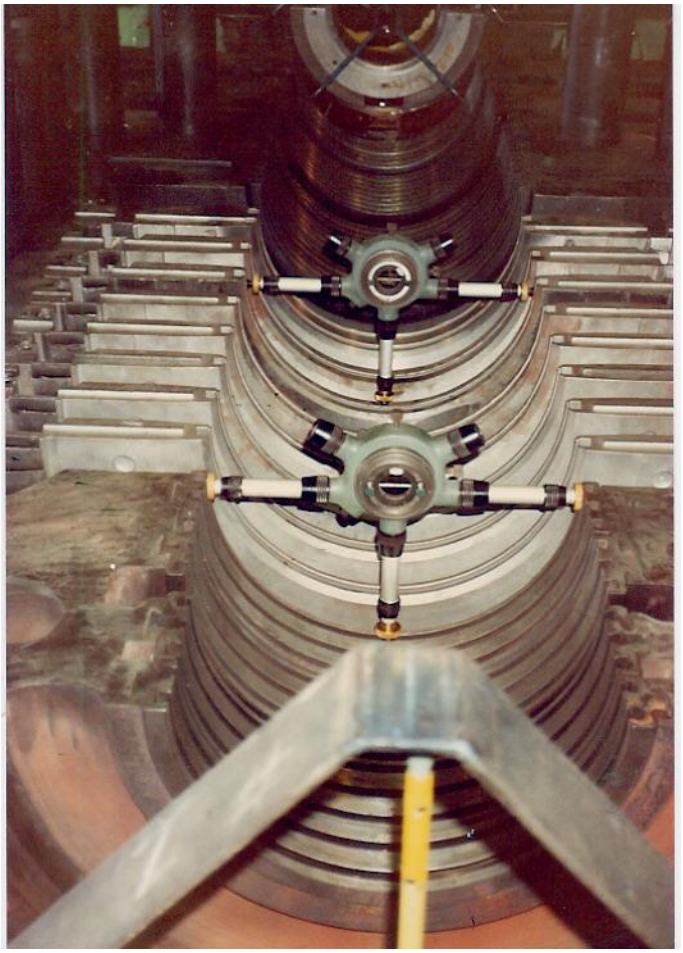


Figure 347. Sighting targets in center of diaphragms

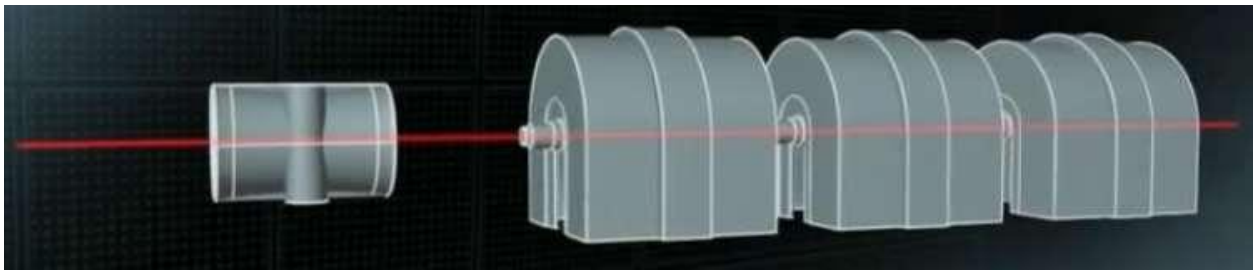


Figure 348. Showing how all the casings are aligned together

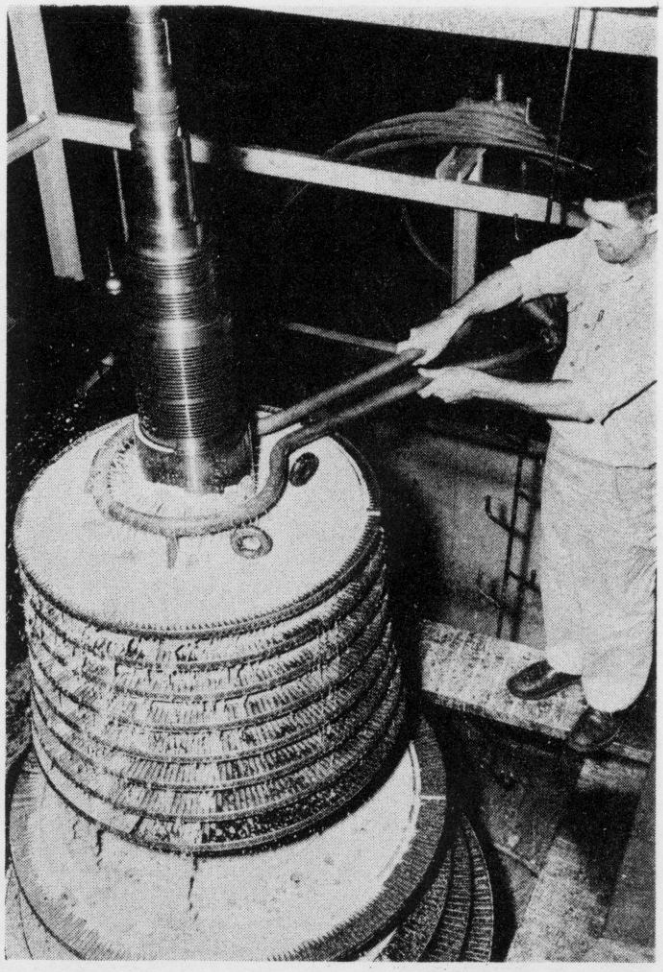
## 5. How do you remove the wheel of an impulse turbine to replace it?

The rotor is removed from the casing and held vertically from a crane with the smaller wheels toward the top. Impulse wheels are shrink fitted to the rotor and sometimes uses a key in a keyway. The rotor is center bored with a hole drilled partway through it. Liquid nitrogen is fed into the hole of the rotor from a tank of liquid nitrogen similar to a welding cylinder. A float with a rod and flag is dropped into the hole to tell the repairman the level of the liquid nitrogen in the hole. He can open the valve on the nitrogen cylinder to adjust the level. This cools the rotor and causes it to shrink in diameter. An arc welder is clamped to either end of the wheel to be removed. The electrical resistance of the welder is used to heat the wheel which causes it to expand and allow gravity to slide it off the rotor. Wooden pallets are stacked just under the wheel to be removed to catch the wheel and prevent damage. If a damaged wheel is in the middle of a set of wheels, the good ones are removed in this way until the bad one is reached. Each time a wheel is dropped, it is removed, the pallets repositioned and the welder clamped to the next wheel

*Detroit Edison Tour*

Assembly of condensing turbine

Figure 349.



**For more reliable turbine performance, assembly of properly designed and machined parts requires men with years of experience in turbine manufacture.**

**After the wheel has been expanded, it is lowered into place, positioned, cooled and shrunk onto the shaft.**

Figure 350.

## 6. What is a shrunk-on-disc rotor?

These are built by heat expanding the discs, so that upon cooling they shrink on the main rotor forging.

## 7. What is the potential problem of shrunk-on-disc type rotor?

It is the failure due to circumferential cracks, which are not limited to old rotors of early models (1960), but they also take place on present-day rotors.

## 8. Why does stress corrosion cracking take place at keyways of shrunk-on-disc rotors of low-pressure turbines?

Keyways locate the shrunk-fit disc into place on the rotor shaft. They improve the rigidity of the connection between the disc and the rotor. Keyways concentrate the centrifugal forces on the disc and the stress at the keyway. Gaps between the key and the rotor and disc allow the chlorides to concentrate at this point. The combination of chemical concentration and high stress can have disastrous consequences. In modern construction, keyways have been eliminated to reduce the danger. Solid forgings of better quality steel have reduced the need for shrunk on discs.

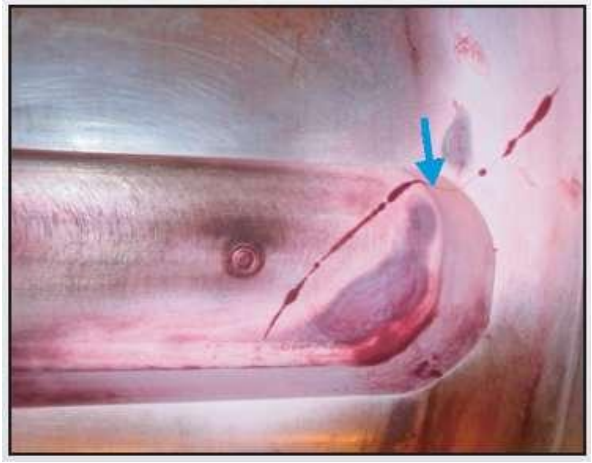


Figure 351. Stress Corrosion Crack at the keyway.

In the early years, many power plants, especially nuclear power plants, experienced low pressure steam turbine disc cracking caused by stress corrosion. Engineers and designers determined that this disc cracking, which is a well known problem in the industry, was caused by some “shrunk-on” disc designs. The designers of the first 1,800 rpm turbines installed in nuclear power plants in the 1970s and 1980s based their designs on fossil turbines built and put into service in the 1950s.

Due to limitations in forging size at that time, the large 1,800 rpm LPs were typically constructed with a central shaft with individual discs shrunk on. In the nuclear steam cycle, the shrunk on designs experienced issues with stress corrosion cracking (SCC) between the disc and the shaft. This had not been seen on the fossil units. Most of the domestic Original Equipment Manufacturers Low Pressure turbines had to be replaced in the 1980s and 1990s.

Many first-generation Low Pressure turbines were replaced by second-generation models with a better design. Most customers have retrofit their original shrunk-on rotor to a Monobloc solid forging to mitigate this stress corrosion cracking (SCC) concern.

## 9. How could a turbine wheel become unbalanced?

If the turbine is kept idle for an extended period without complete drainage of exhaust casing, the solid matter can deposit in the lower half of the wheel causing unbalance.

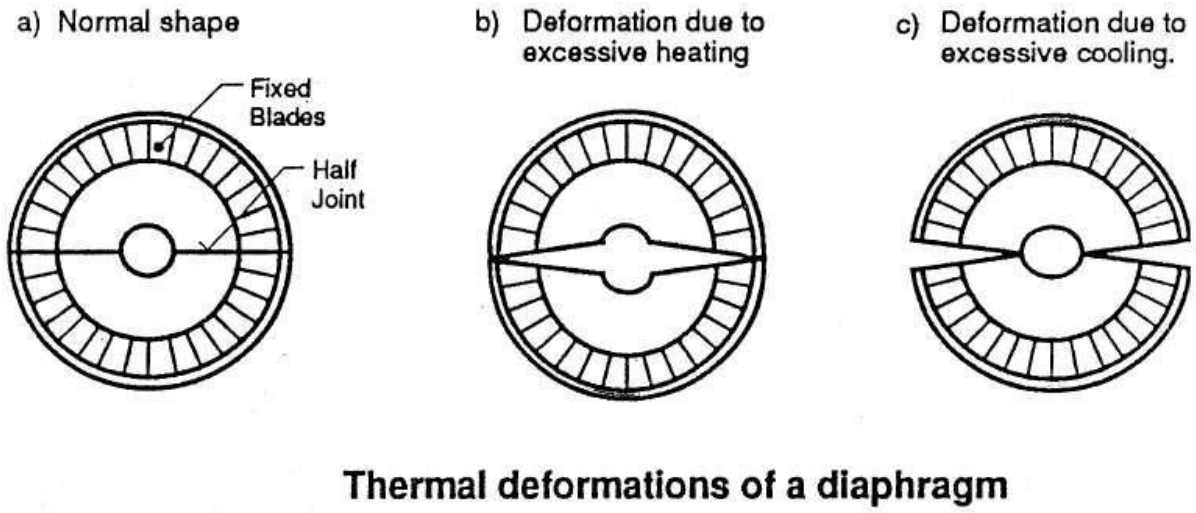

a) Normal shape
Fixed Blades
Half Joint
b) Deformation due to excessive heating
c) Deformation due to excessive cooling.
Thermal deformations of a diaphragm

Figure 352.

## 10.Another form of vibration is that of the disk edges. What causes this and how is this avoided?

Vibration of disk edges can be caused by the force of a steam jet leaving a nozzle and passing through the blades on the edge of the disk as it turns past one location in the casing. These vibrations depend on dimensions and weights of the disks and are avoided by proper design.

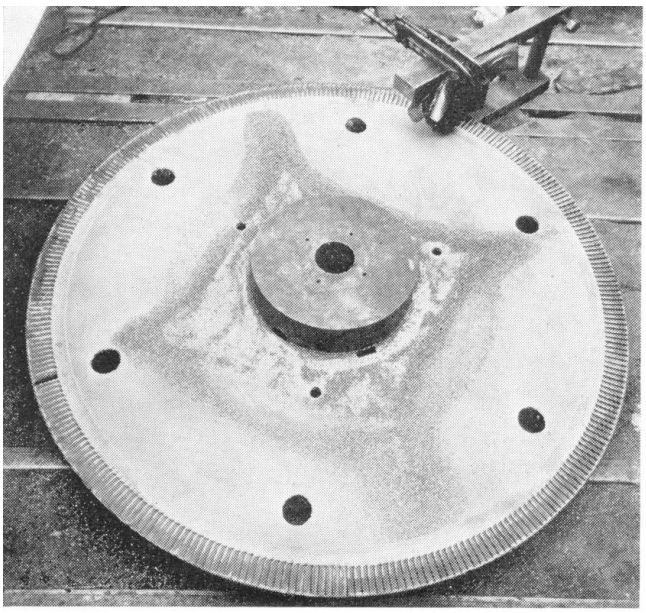


Figure 353. A vibrator is attached to a turbine wheel with grains of sand on top to show that at a certain vibrating frequency, a pattern will develop that shows how stress is building up with a four pointed pattern at this particular speed

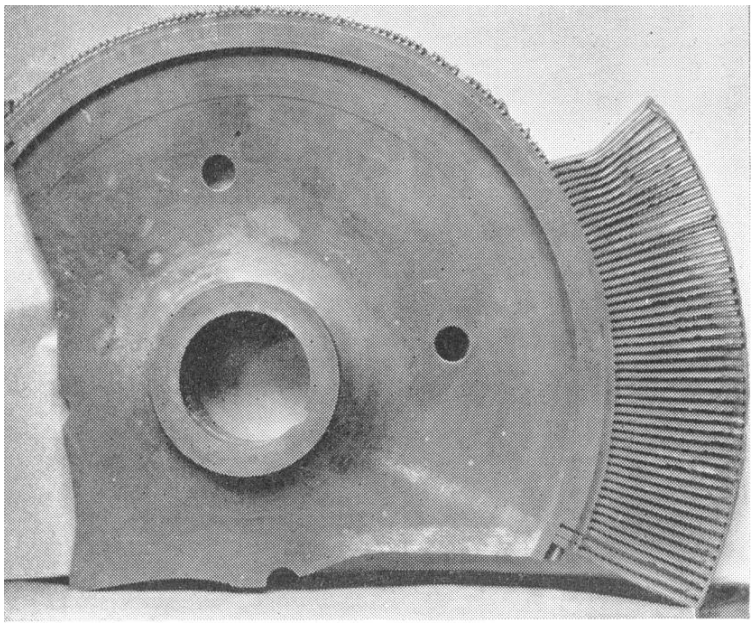


Figure 354. An actual turbine wheel that has fractured along the lines shown in the picture at the left. If the speed of the turbine matches that frequency, catastrophic failure can result.

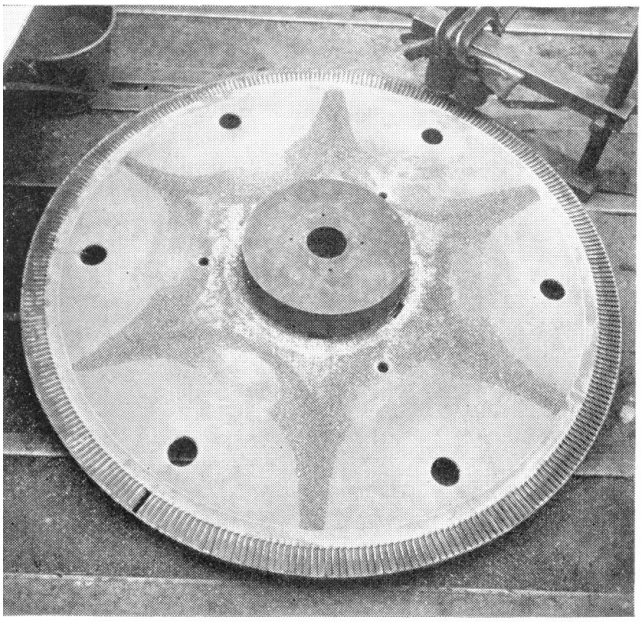


Figure 355. At a different frequency, a six pointed pattern develops

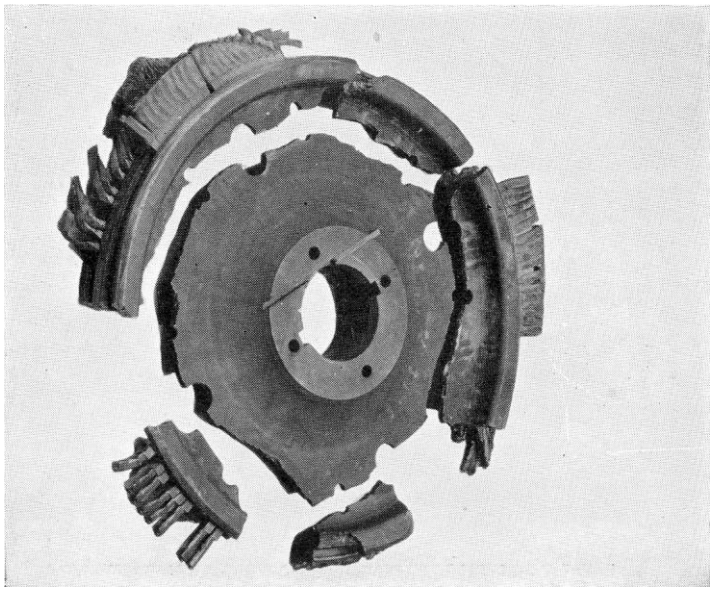


Figure 356. A turbine wheel that has shattered by running at a critical speed that induced similar vibrations

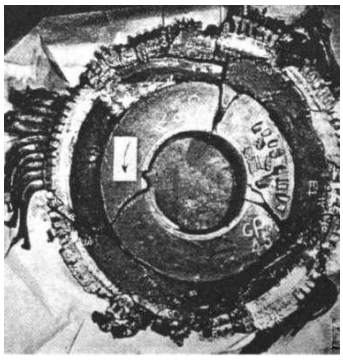


Figure 357. shattered turbine wheel

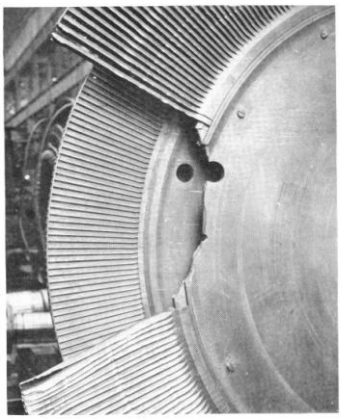


Figure 358. A turbine wheel that has thrown a chunk of the wheel similar to the vibrating pattern

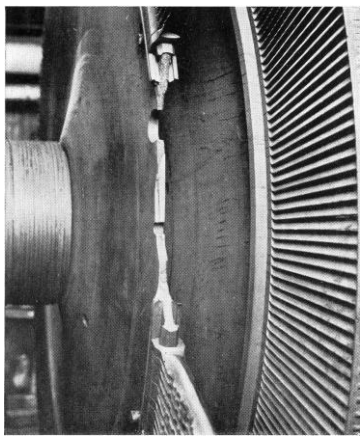


Figure 359. The same wheel as at the left from a side view

## 11. What should be done if excessive vibration is due to an unbalanced turbine wheel?

The turbine wheel is to be checked if it became unbalanced due to overspeeding. The turbine wheel must be re-balanced or replaced

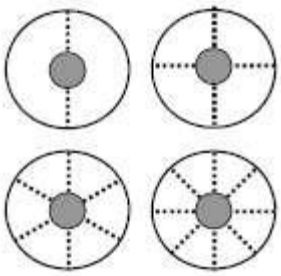


Figure 360. A diagram of the patterns developed at different critical speeds

Figure 361. A turbine wheel that has failed, throwing the buckets from the wheel

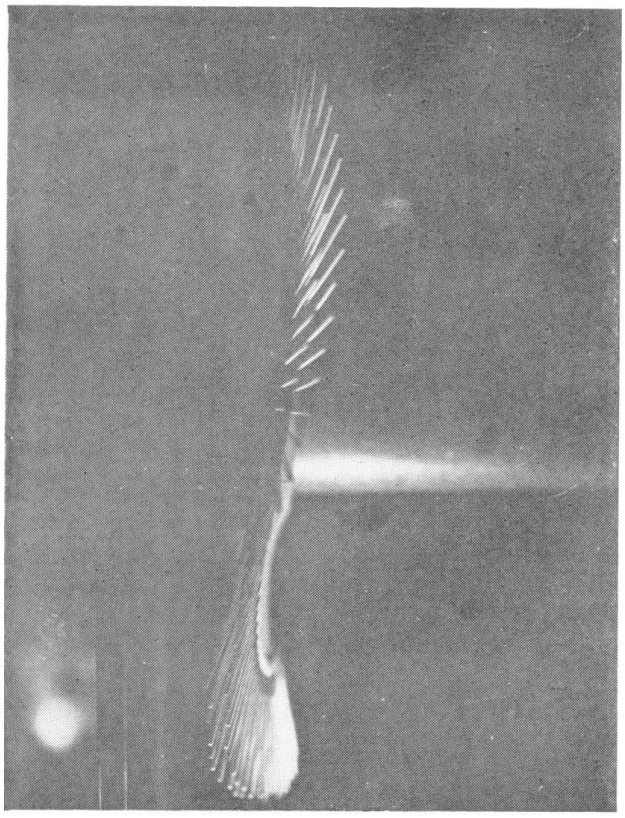


Figure 362. An India rubber model of a turbine wheel taken with a high speed camera showing how different speeds will cause the wheel to oscillate

# Chapter 8 Nozzles

## 1. Why are hand-operated nozzle valves used?

Hand-operated nozzle valves are used to permit changing the number of working nozzles for better efficiency at part-load and overload operation. This permits changing the number of nozzles groups in service, as total steam flow changes. It enables a turbine to deliver its rated capacity with reduced steam pressure, permits liberal overload capacity with normal steam pressure, and achieves good economy at low loads by cutting some nozzles out of service.

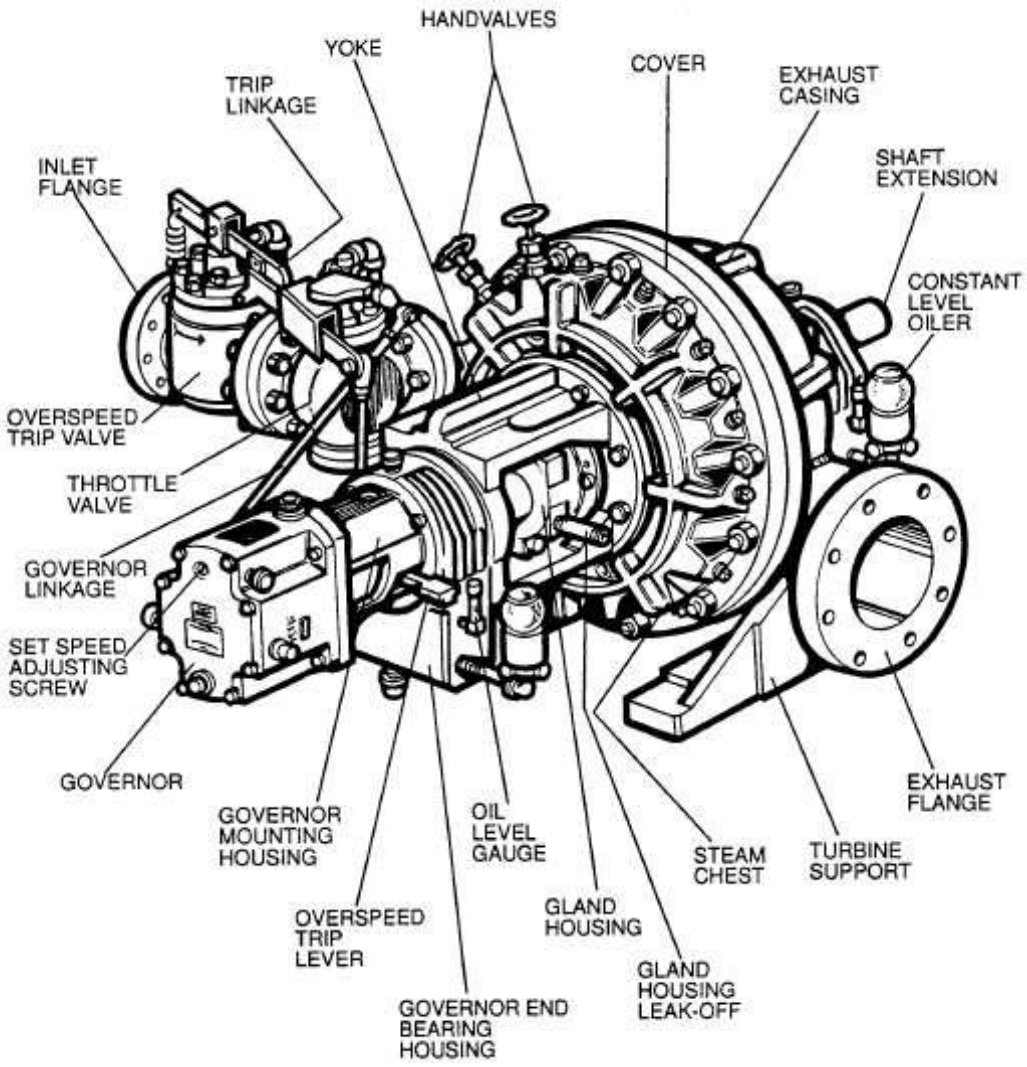



Figure 363. The hand valves in the upper portion of the diagram can be opened to adjust the turbine to handle increased load. If you look carefully, you will see pipe plugs around the periphery of the turbine where other hand operated nozzle valves can be installed

## 2. What are the two basic types of nozzles? Explain.

Two basic types of nozzles are converging and diverging. Two important parts are the throat and mouth. The throat is the part with the smallest cross section area. The mouth has the largest cross section area.

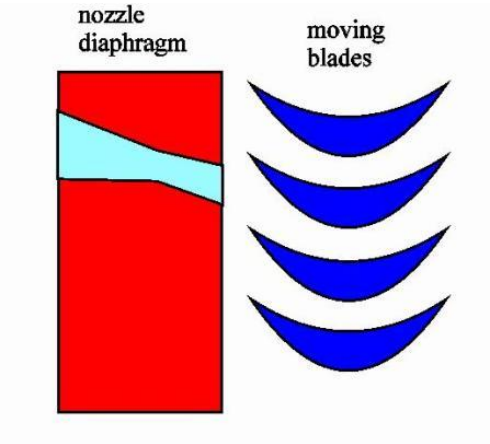



Figure 364. Converging nozzle in a cross section of the diaphragm

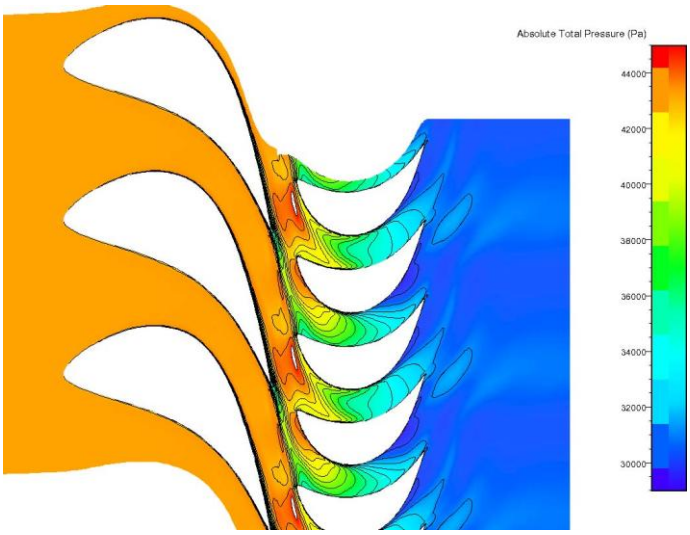



Figure 365. The nozzles formed inside the diaphragm of this drawing converge and then diverge

## 3. What type of nozzle is usually used on a single stage impulse turbine? Name all parts or sections of this arrangement.

Nozzles for a single stage impulse turbine are usually of the diverging type.

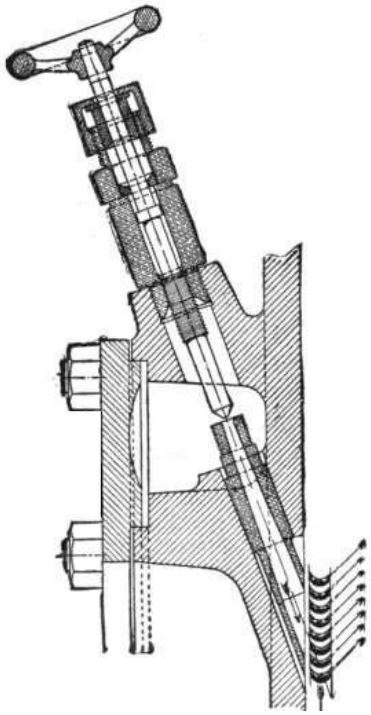


Figure 366. Diverging nozzle

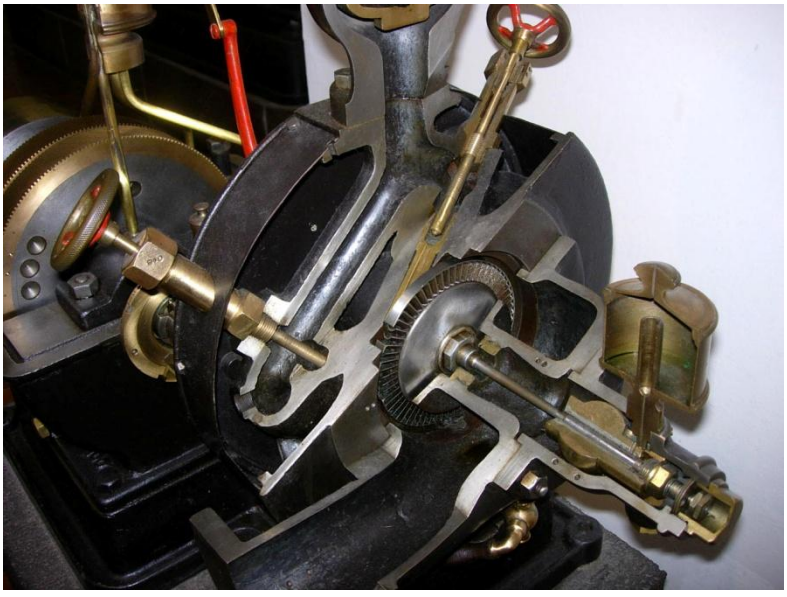


Figure 367. Cutaway of small turbine nozzle and wheel

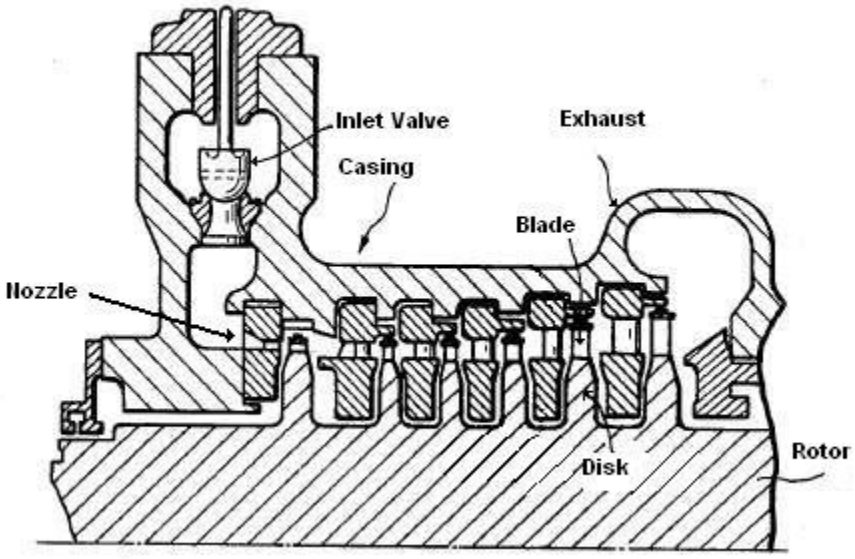



Figure 368. One converging nozzle followed by 5 stages of reversing buckets

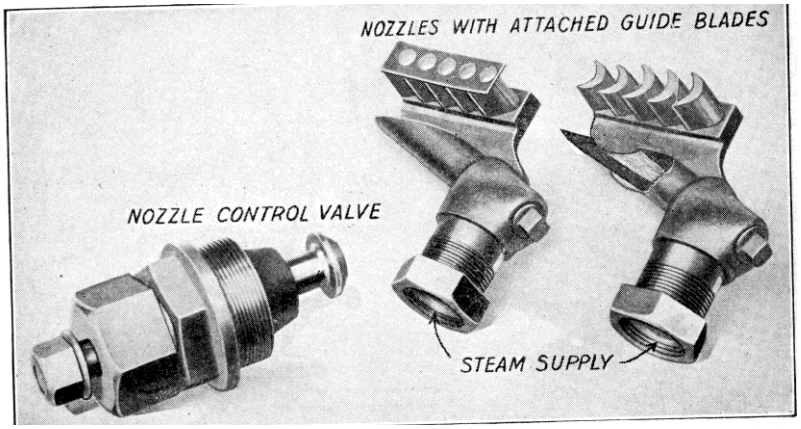



Figure 369. Nozzle control valve on the left. The steam supplies nozzles that fit between two turbine wheels. The guide blades attached to the nozzle reverse the steam flow. This is only needed in the area next to the nozzle.

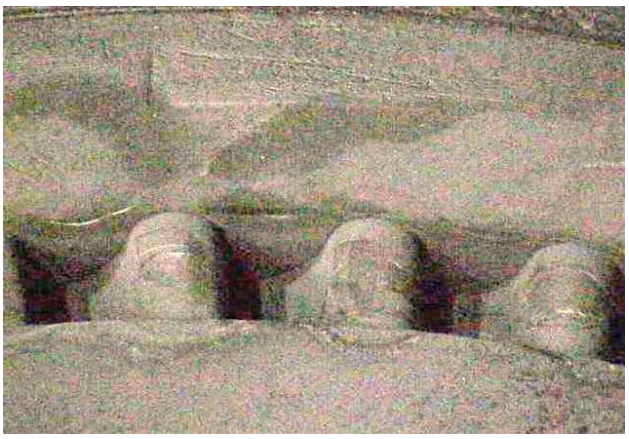


Figure 370. Steam inlet to nozzles in the diaphragm

Figure 371. Steam outlet from the diaphragm. These teardrop shapes form a converging-diverging nozzle

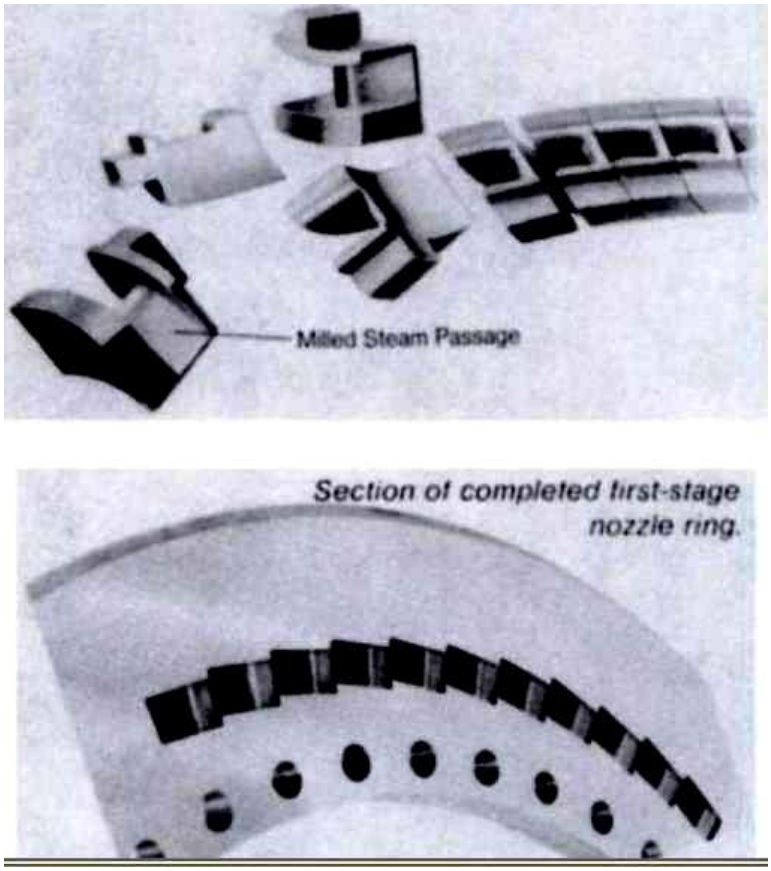



Figure 372. Milled blocks are assembled together to form a nozzle ring

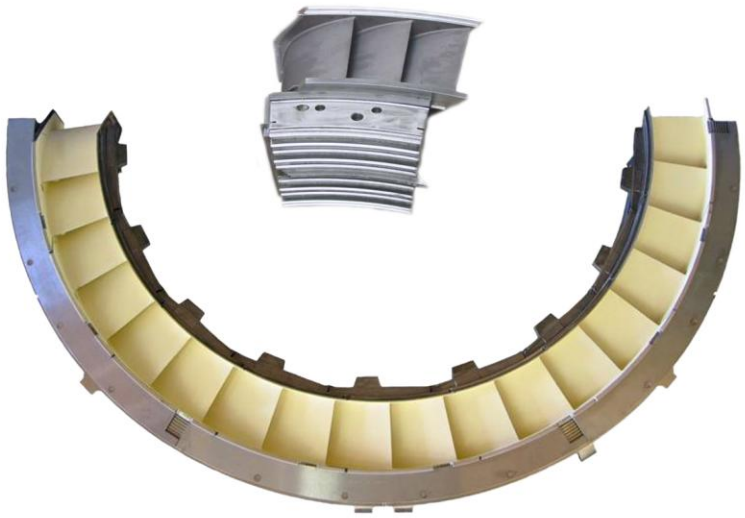


Figure 373. Assembled nozzle ring

# Chapter 9 Main Steam and Throttle Valves, Bar Lift and Cam Lift Admission Valves

## 1. Explain the bar lift type admission valves on a turbine.

The bar lift mechanism opens the valves in desired sequence with the same rate of opening for all valves. Valve stems pass through holes in a bar which is raised and lowered by the governor mechanism. Collars on each valve stem are set at different heights. Hence, as the bar rises, valves lift in a sequence determined by the collar settings. This opening of the nozzle groups, in series, gives more efficient operation at partial loads.

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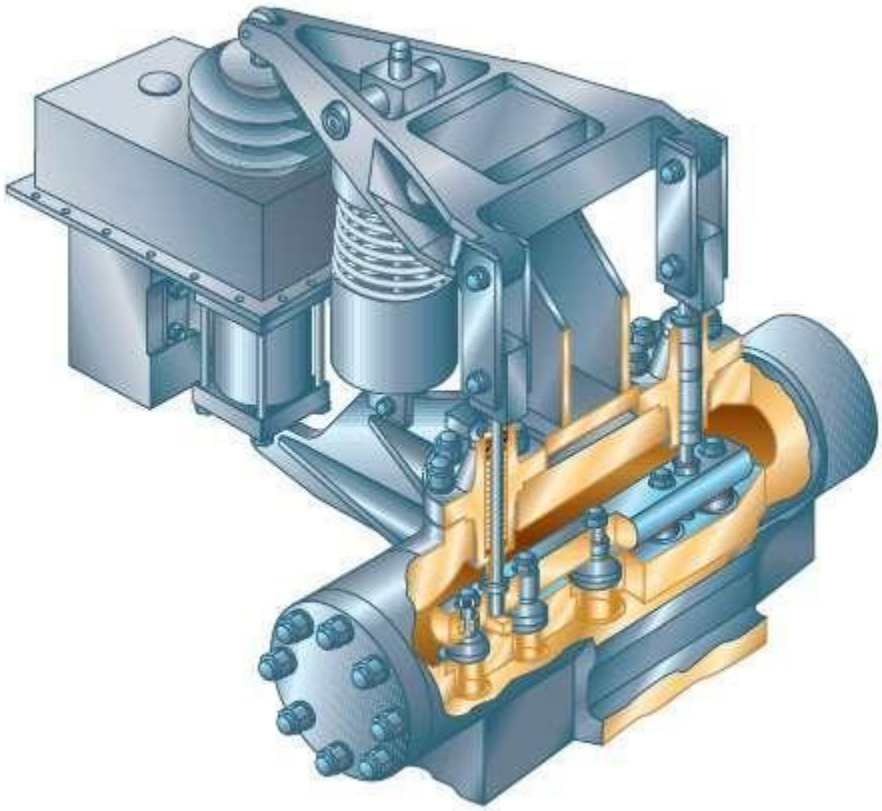


Figure 374. Bar Lift. Notice how the valves are different sizes and different stem lengths.

## 2. How are admission valves controlled on large turbines? Draw the bar lift inlet type.

On large turbines, admission valves are controlled by the governor mechanism which opens the valves in a certain sequence. Two typical ways this is done is 1) a camshaft and cam for each valve 2) a bar lift.

On the bar lift type, the collars on each valve stem are set at different heights. As the bar rises, valve sequence is determined by collar setting. This opening of the nozzle group in series gives more efficient operation at part load.

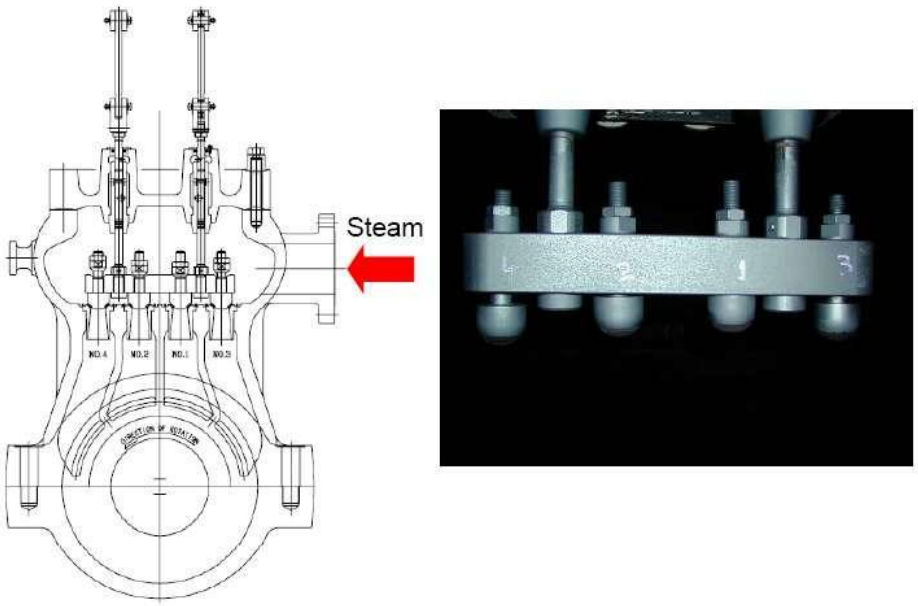



Figure 375. Bar Lift Mechanism

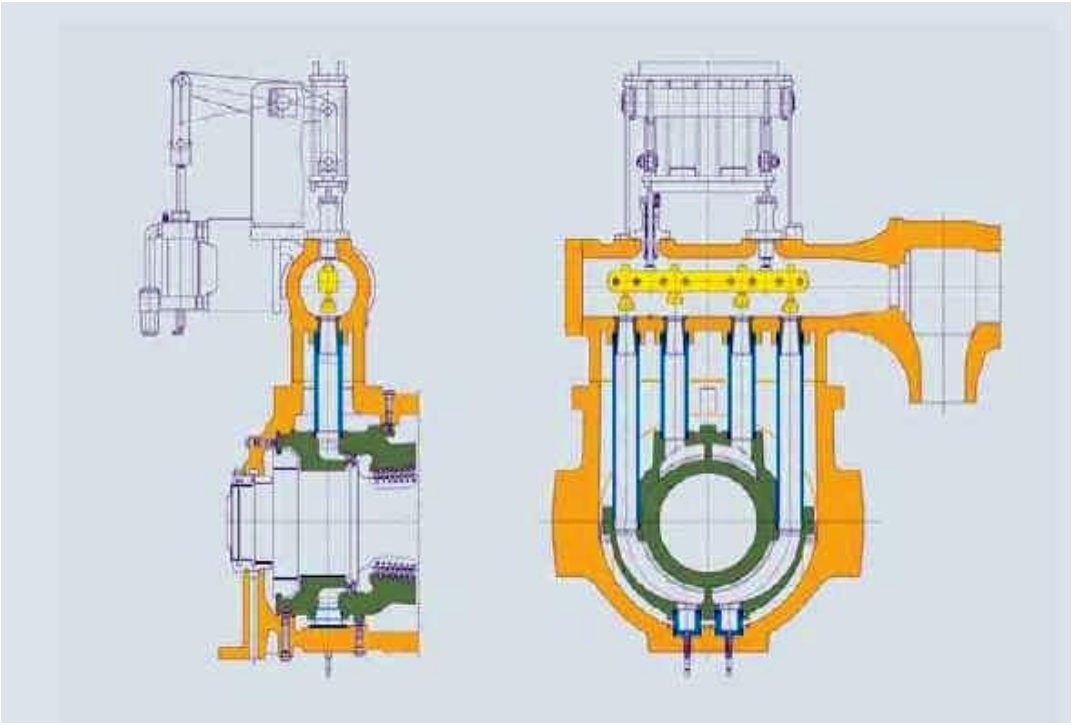


Figure 376. Bar Lift admission valves

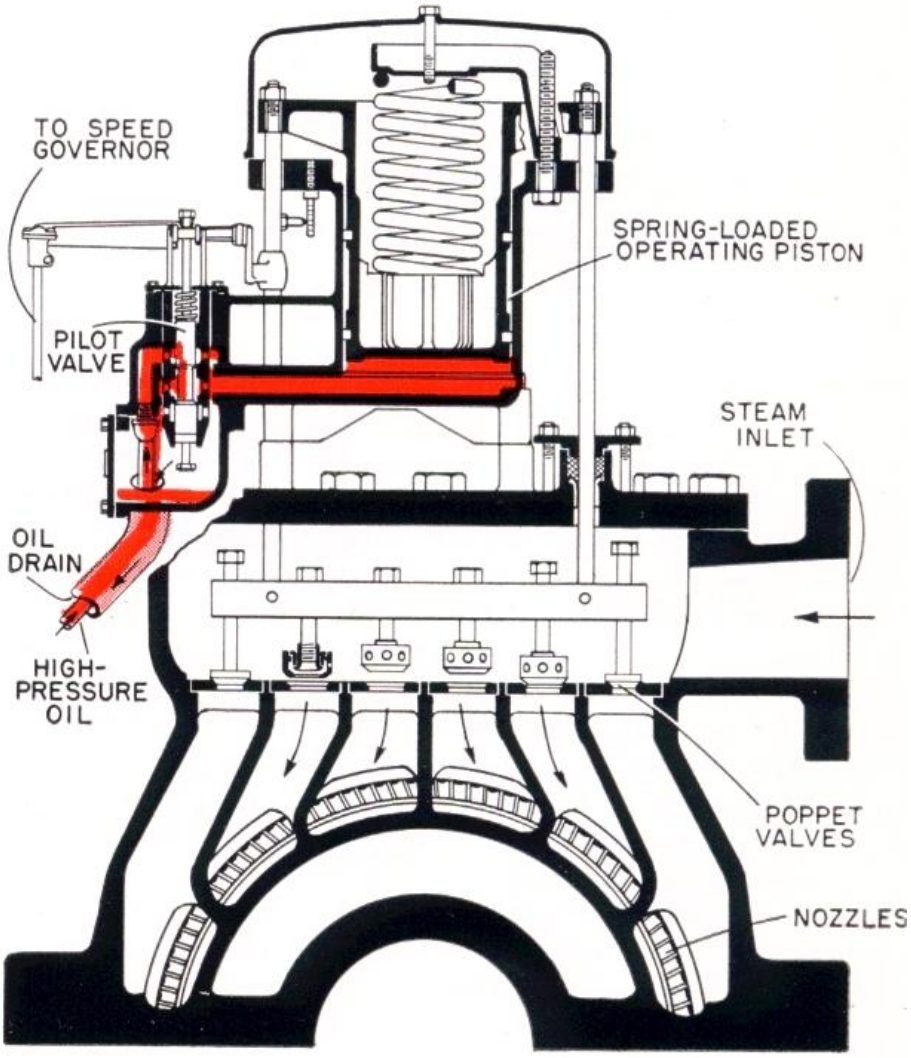



Figure 377. Bar lift with hydraulic actuator

Figure 378. Note the different lengths of the valve steams to open the valves at different points of the lift of the bar

Figure 379. Bar lift mechanism being overhauled at Michigan State University

## 3. Explain the cam lift type admission valves on a turbine.

The governor operates a camshaft which carries a cam for each steam admission valve. Cam position and shape determine the sequence and rate of valve opening.

*S&V page 73*

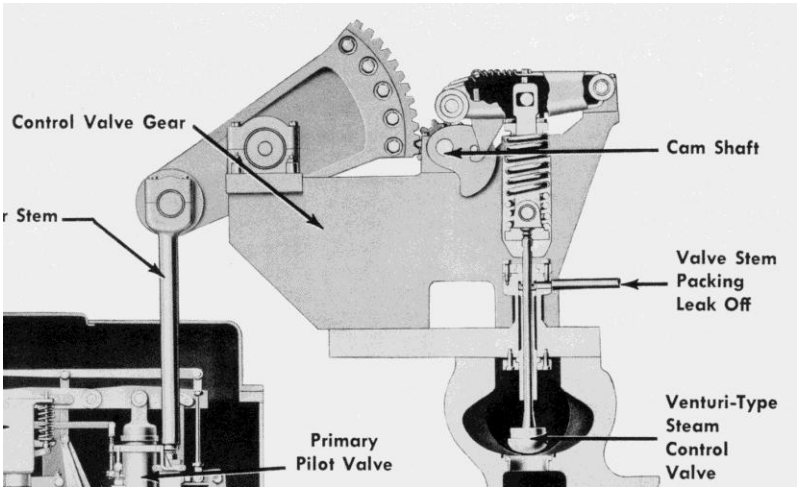



Figure 380. Cam lift actuating mechanism

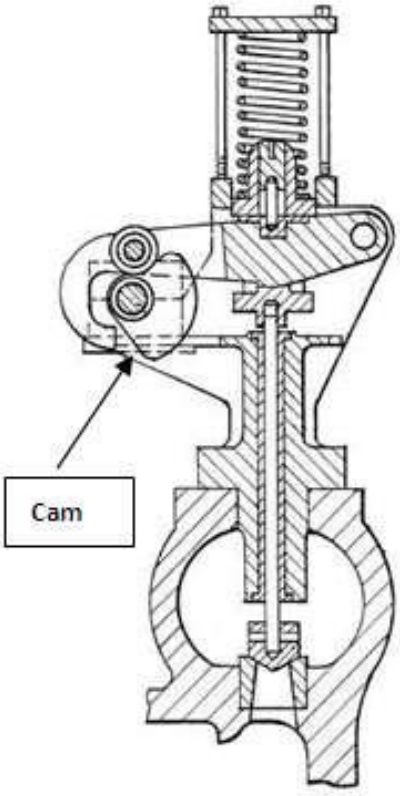



Figure 381. Cam lift schematic from the side

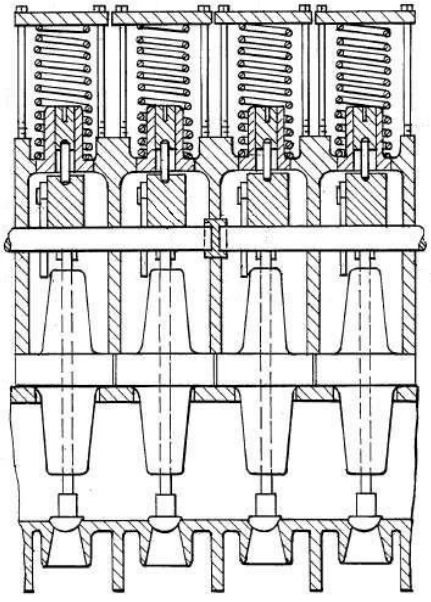


Figure 382. Cam lift schematic from the front

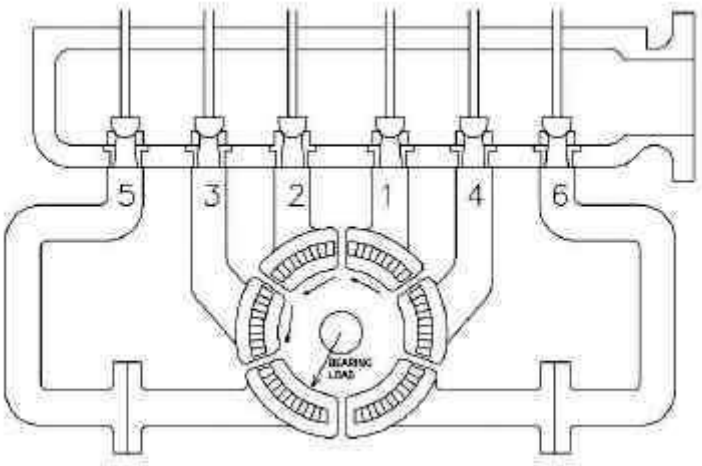



Figure 383. Cam lift schematic showing how all sections of the first stage of the turbine can receive steam

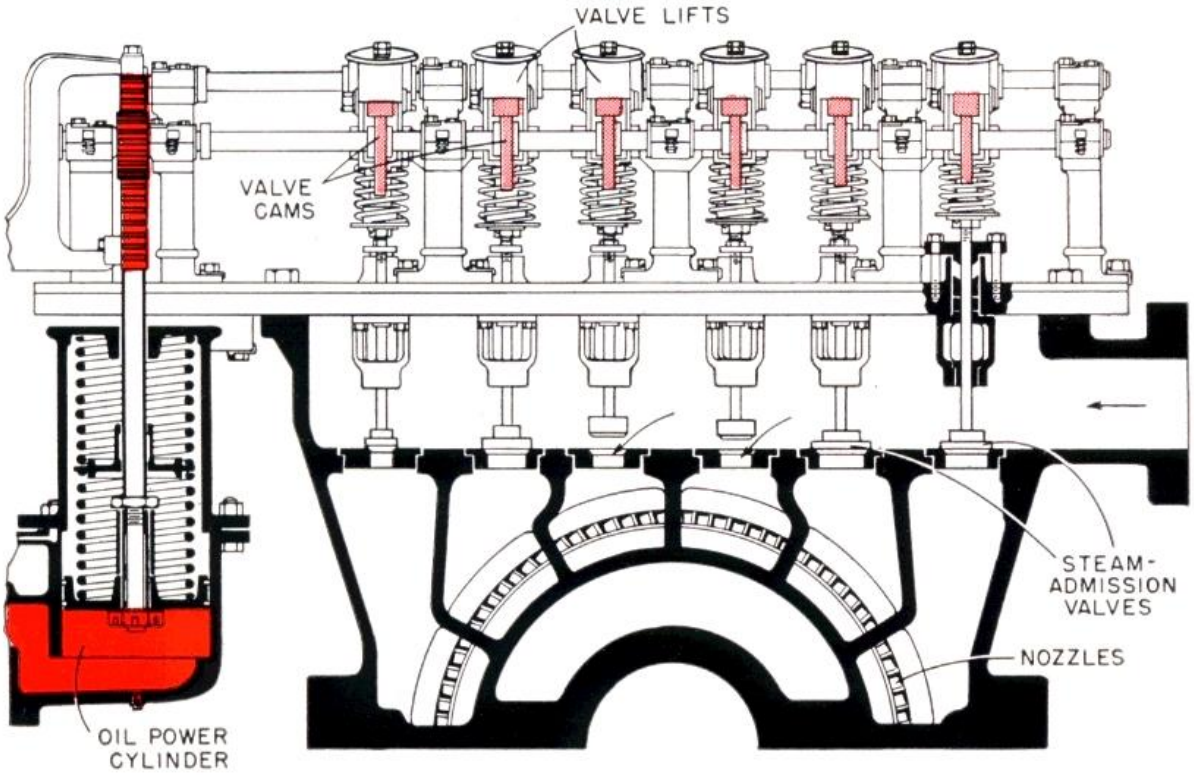



Figure 384. Hydraulic actuator with gear rack rotates the cam shaft to open the steam admission valves at different times

## 4. What is an advantage of the diffuser type of valve seat?

An advantage of the diffuser type of valve seat is that it permits high steam velocities through the throat with small pressure drop, and so helps to reduce the size of valves and valve gear. .

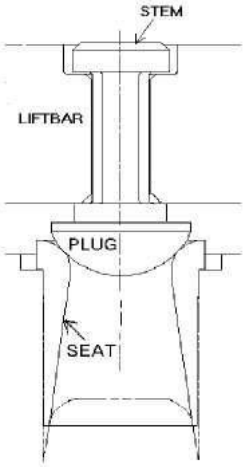



Figure 385. Diffuser valve in closed position on its seat

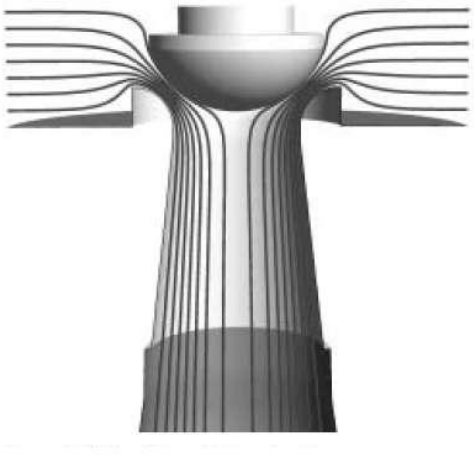


Figure 386. Diffuser valve opening and allowing steam to enter

## 5. What apparatus is installed in the steam line just ahead of the turbine throttle?

The throttle valves on large turbines are the devices that provide admission of steam to the first stage of the turbine. This is generally controlled by the governor through the cam or bar type lift. Ahead of this valve is the main steam stop valve or the emergency stop valve depending on the design and set up. This could be two valves built into one, or could be two separate valves.

*Croft Turbines page 143*
*Grubb Notes "Turbine Section"*

If the speed of the turbine exceeds a safe limit (10 percent above normal speed), an overspeed trip device is provided. This trip is eccentrically mounted and restrained by a spring to trip simultaneously the governor valve and the butterfly valve. Hand reset is provided when the speed has been reduced to normal. In normal operation the butterfly valve is held open by the trip linkage against the force of the coil spring. In some cases the butterfly trip valve is omitted, and overspeeding closes merely the governor valve.

*Steam Plant Operation. Woodruff and Lammers, 5th Edition. page 443*

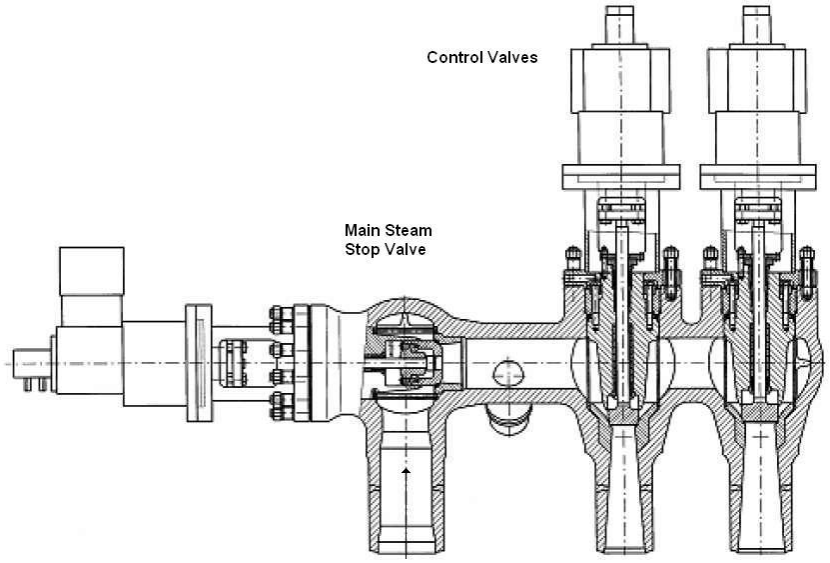



Figure 387. Main steam stop valve is located ahead of the governing valves

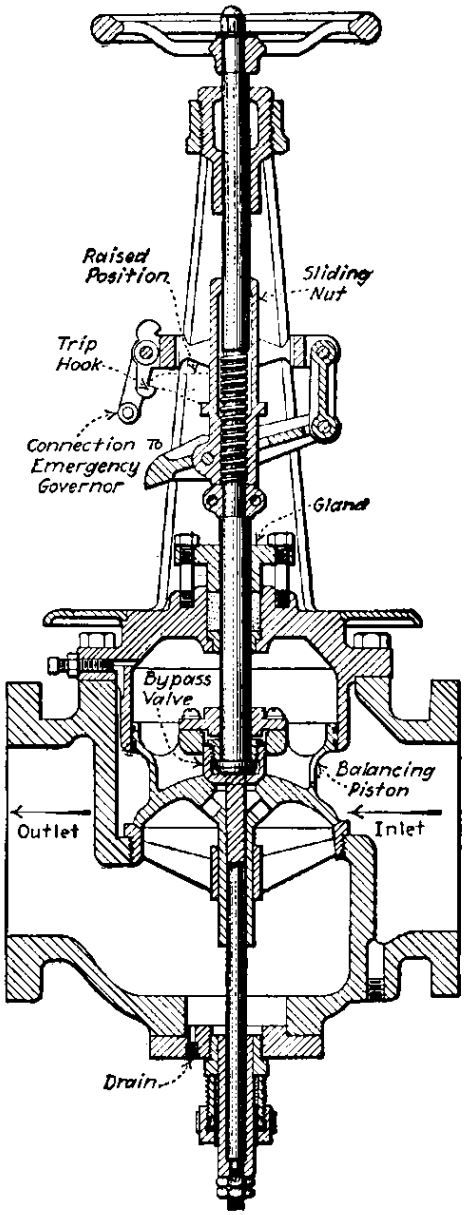



Figure 388. Throttle valve with safety-stop attachment used on some *General Electric Co.* Curtis turbines. (Many are in use but they are now applied to new machines only in special cases.)

**6. How is steam flow controlled to turbines? Draw and explain an "automatic-stop throttle valve".**

Steam flow to turbines is generally controlled by stop valves for open and shut service and a throttle valve to regulate steam flow during operation. These functions can be combined into one valve. There can be two parts, the valve in the steam line, and the operating mechanism.

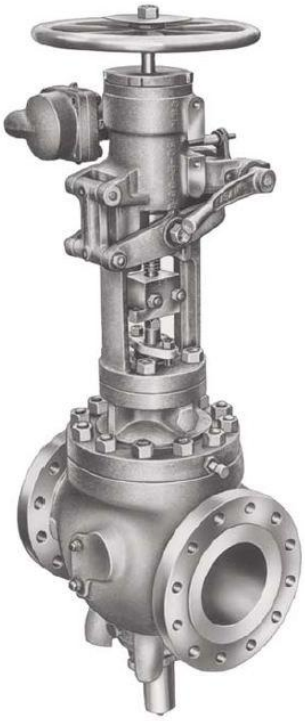


Figure 389. Automatic stop and throttle valve with trip lever.

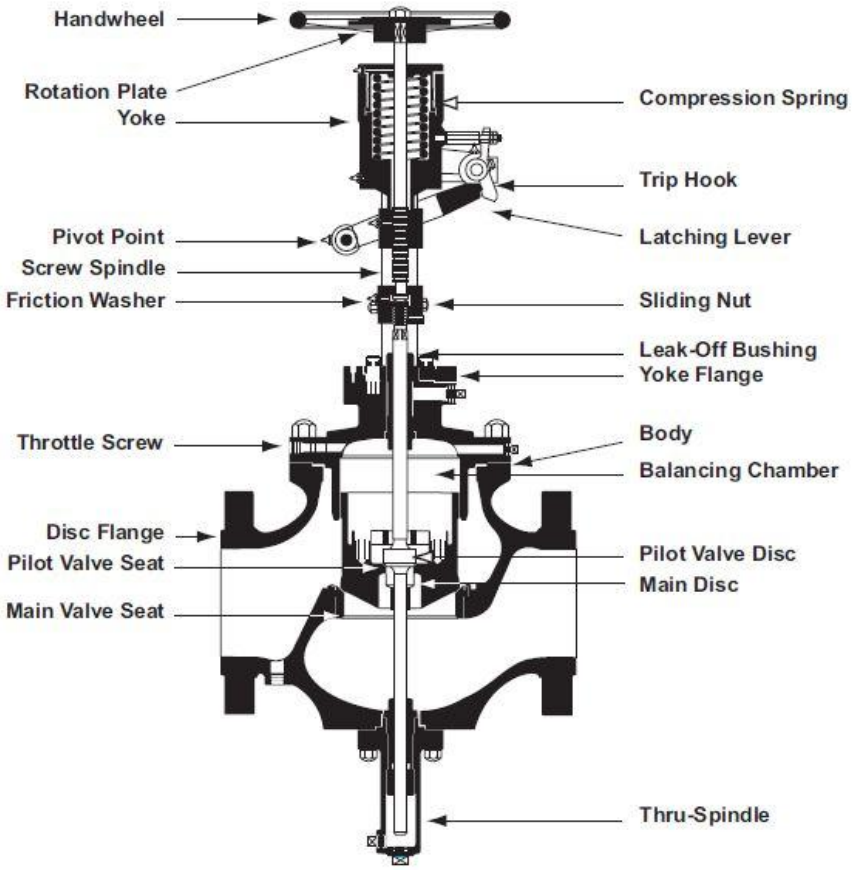



Figure 390. Details of throttle/stop construction

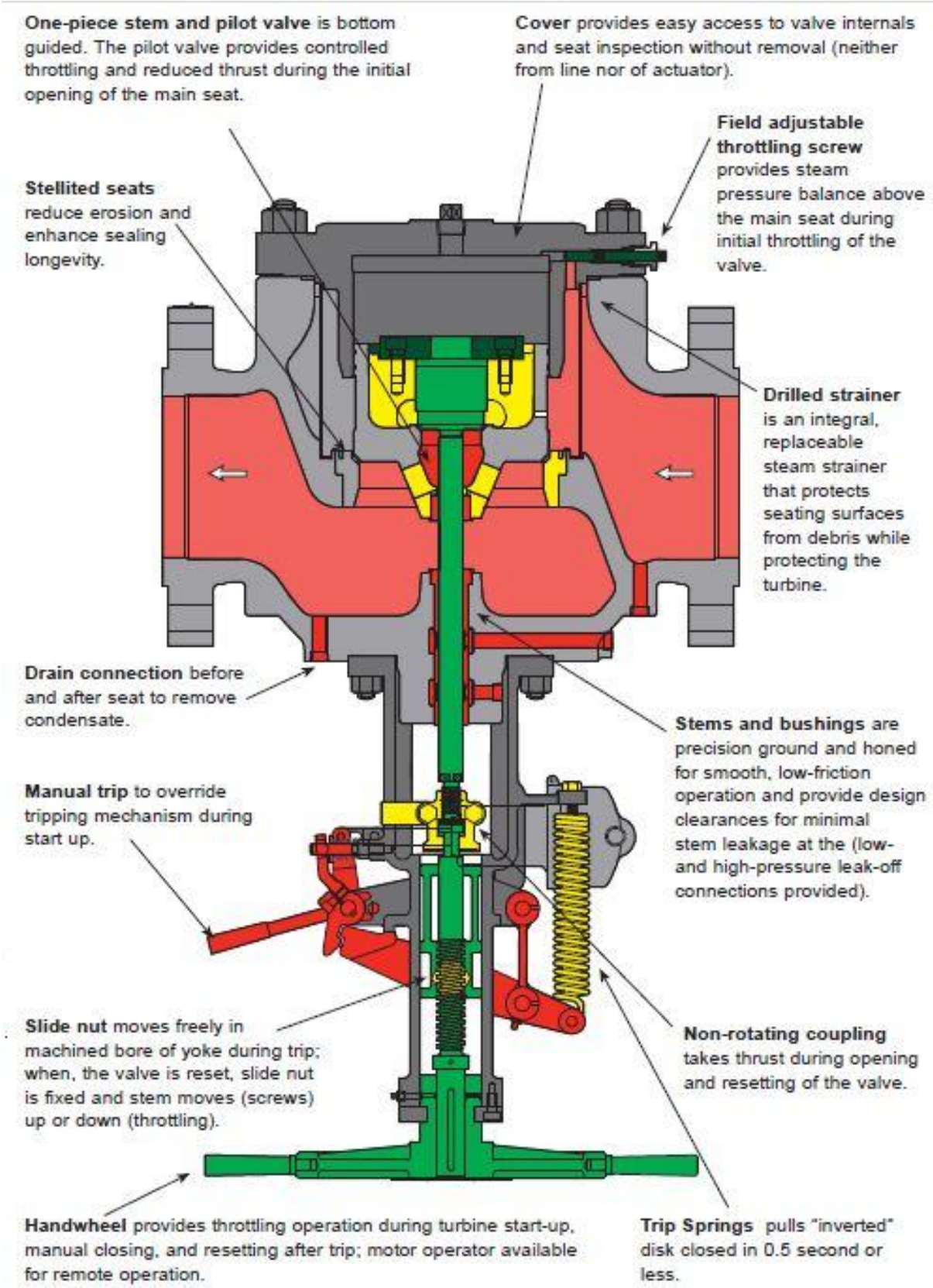

**One-piece stem and pilot valve** is bottom guided. The pilot valve provides controlled throttling and reduced thrust during the initial opening of the main seat.
**Cover** provides easy access to valve internals and seat inspection without removal (neither from line nor of actuator).
**Field adjustable throttling screw** provides steam pressure balance above the main seat during initial throttling of the valve.
**Stellited seats** reduce erosion and enhance sealing longevity.
**Drilled strainer** is an integral, replaceable steam strainer that protects seating surfaces from debris while protecting the turbine.
**Drain connection** before and after seat to remove condensate.
**Stems and bushings** are precision ground and honed for smooth, low-friction operation and provide design clearances for minimal stem leakage at the (low- and high-pressure leak-off connections provided).
**Manual trip** to override tripping mechanism during start up.
**Slide nut** moves freely in machined bore of yoke during trip; when, the valve is reset, slide nut is fixed and stem moves (screws) up or down (throttling).
**Non-rotating coupling** takes thrust during opening and resetting of the valve.
**Handwheel** provides throttling operation during turbine start-up, manual closing, and resetting after trip; motor operator available for remote operation.
**Trip Springs** pulls "inverted" disk closed in 0.5 second or less.

Figure 391.

**7. How can the problem of excessive speed variation due to throttle assembly friction be overcome?**

The throttle should be dismantled. Moving parts should be checked for free and smooth movement. Using very fine-grained emery paper, the throttle valve seats and valve steam should be polished.

**8. What happens to boiler pressure when the turbine speed increases?**

A speed increase would mean a load drop. This would cause an increase in boiler pressure as the governor closed off steam to the turbine to slow it down.

*Tour Guide at Trenton Channel Detroit Edison Plant*

## 9. How do valves and seats differ between those made for high temperatures & pressures and those made for low pressures?

High temperature & pressure valves and seats, those operating above 750 F. and 600 psi, are generally stellite-trimmed.

Figure 392.

Figure 393. Stellite snout

## 10.What might be called a disadvantage of the straight reaction turbine?

A disadvantage of the straight reaction turbine is that it requires that steam be admitted to 100% of the drum periphery. This limits flexibility in starting and efficient load control.

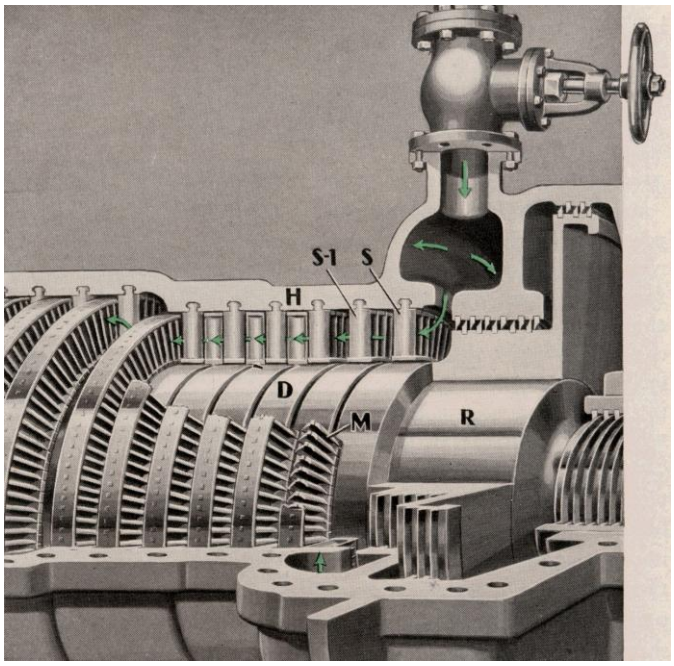



Figure 394. Full arc admission with a single inlet valve

## 11. Explain a single-inlet valve on a turbine.

A single-inlet valve is used on reaction turbines. It can be the double-seated type and practically balanced. This reduces the power required for its operation. The seating surfaces of the valves and seats are stellited. A gland is used for the valve stems, with leakoff between the inner labyrinth and the outer packing gland. The mechanism for opening and closing each valve has a cam mounted on a shaft which is rotated by the governor. There are two levers pivoted in the center for each valve. Two levers make both opening and closing occur by positive action of the cam. The coil spring on top assists in closing the valve.

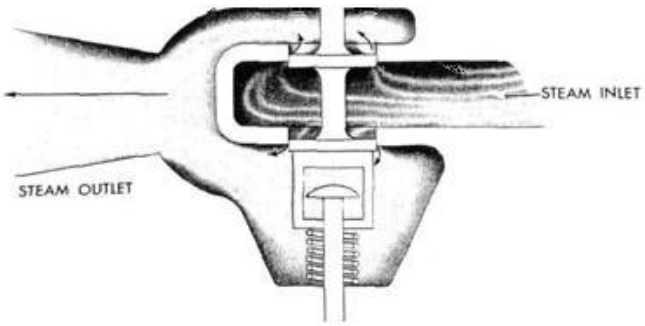



Figure 395. Balanced valve.

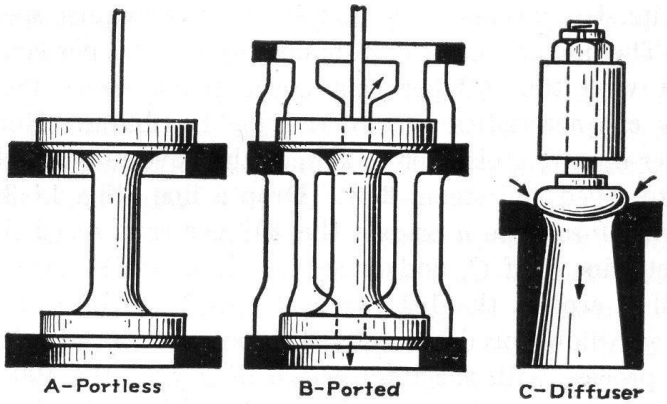
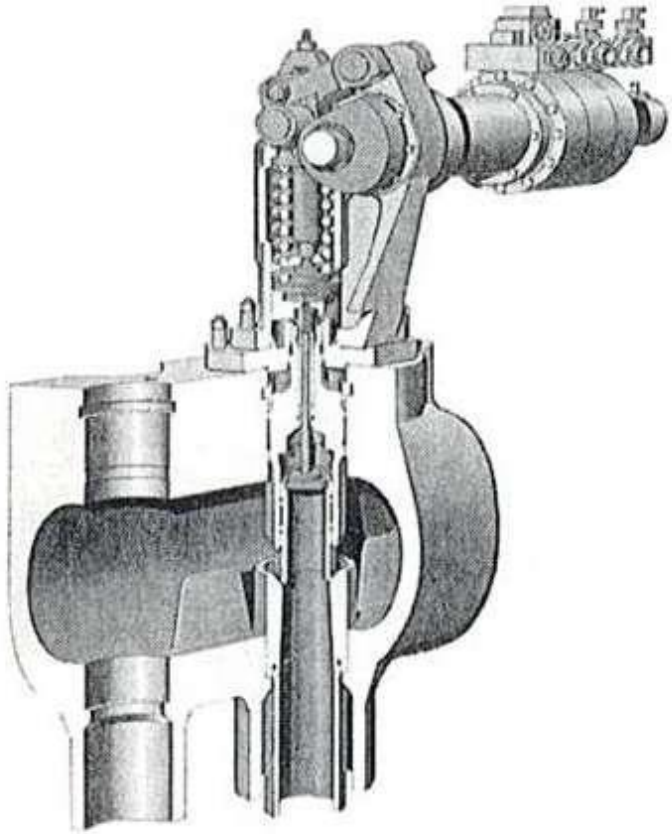



Figure 396. Two balanced valves and one diffuser valve.



Control valve (admission valve) with cam drive.

Figure 397. Single inlet cam admission valve

# Chapter 10 Governors and Overspeed Trips

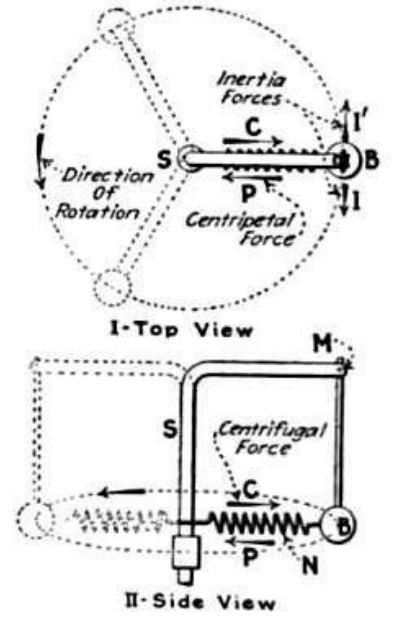
**1. Who invented the first governor for controlling steam pressure?**

James Watt born 1736 – died 1819. He invented his centrifugal governor in 1788.

Figure 398. James Watt

Boulton & Watt engine of 1788

Figure 399.




Showing forces developed by a revolving governor weight.

Figure 400.

**2. Explain centrifugal governor principles**

A governor is a device for keeping a steam turbine reasonably constant. A properly operating governor may be regarded as a permanent watchman, overlooking the turbine with an observant eye. If more power is required as the turbine starts to slow, the weight of the governor flyweights and the spring tension allow the weights to go toward the spindle, opening the steam valves and allowing the turbine to accelerate to its set speed. If the weights fly out against the spring tension due to the centrifugal force of increased speed, the steam valves move toward the closed position, lowering the speed to its setpoint. Centrifugal force is ordinarily the only force employed in flyball or flyweight governors. Centrifugal force is the tendency of a rotating body to move away from its axis of rotation. In governor design this force is opposed by a centripetal force which is introduced by arms, weights, springs or other mechanism. To be in equilibrium at a particular speed the centripetal force must be exactly equal and opposite to the centrifugal force. A handwheel on the front of the turbine can be used to change the spring tension, thereby adjusting centripetal force, and turbine speed or load carrying ability.

*Croft Steam Engines 1922, pages 193-195*

### 3. What prevents the steam pressure in a turbine's steam chest from becoming too high?

The governor-controlled admission valve contained in the steam chest.

*Woodruff & Lammers page 479*

### 4. Explain a simple direct acting flyball governor.

Flyballs are connected to turbine shaft and rotate at a rate proportional to turbine speed. Arms connect weights to a sliding collar, a lever connects collar to governor valve. It operates on the principle of centrifugal force

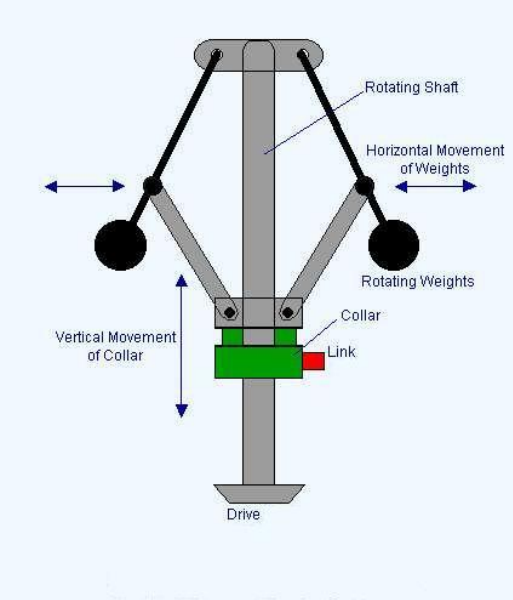



Figure 401.

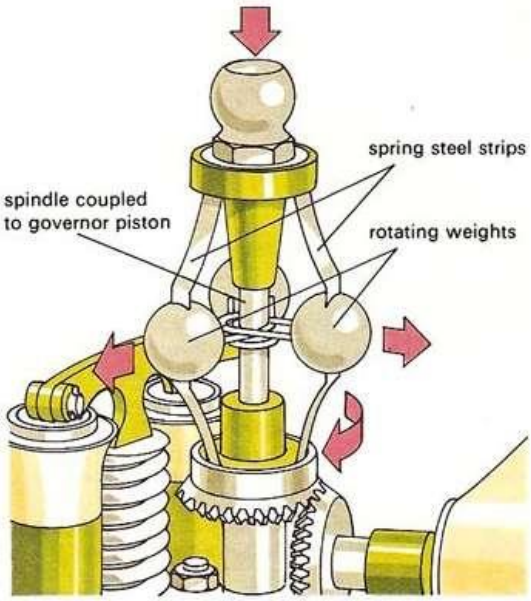



Figure 402.

### 5. What can you say about centrifugal weight governor characteristics?

On a centrifugal weight governor, centrifugal force depends on the diameter of the circle of rotation, on the weight, and on the speed.

Figure 403. Flyball governor in action

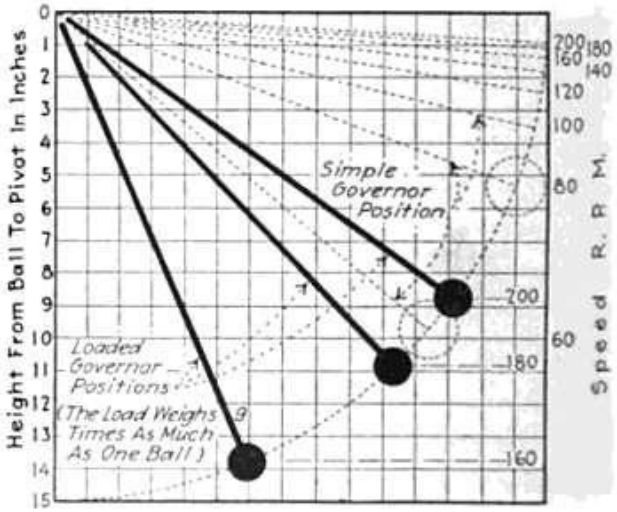



Figure 404. —Showing theoretical positions of balls of simple and of loaded governors at different speeds. (Arms are assumed to be weightless. The bails lift nothing but themselves and, if specified, a centrally attached load.)

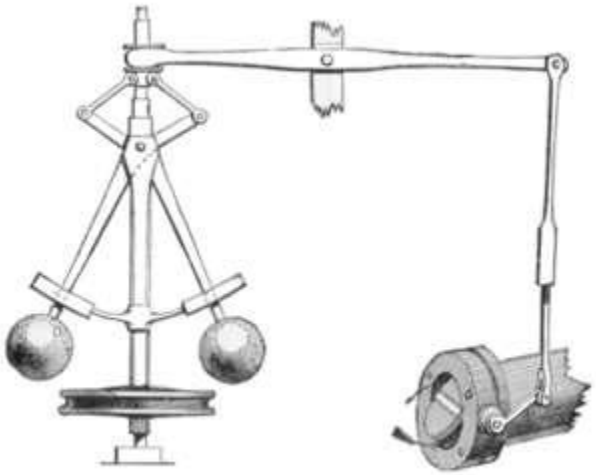


Figure 405. Flyball governor connected to butterfly valve showing principle of operation

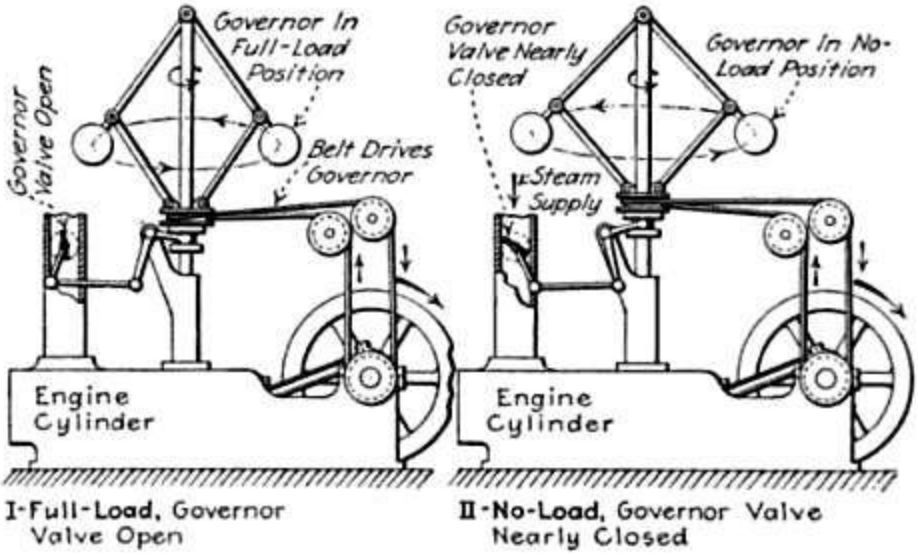



Figure 406. Showing principle of flyball governing to control speed with a steam engine instead of a turbine but the same principles apply.

## 6. What are the limitations of a so called "centrifugal governor"?

1. Change in speed accompanies a load change.

2. It is comparatively insensitive.

3. It must be built in large sizes to obtain large operating forces unless a hydraulic servo-motor is used to amplify the forces of a small flyball or "flyweight" governor.

## 7. How much force would be required to move a 5" valve against an unbalanced force of 400 lbs. in a direct acting governor? (You can see by this question why it is necessary to use various systems of oil pressure relays.)

A 5" valve opening against an unbalanced pressure of 400 PSI requires a force at the start of about 7,800 lbs. (diameter squared multiplied by .7854. Multiply that result by 400) .7854 is a constant for finding the area of a circle. .7854 is one quarter of PI.

## 8. In small turbines, how are admission valves made so that the governor will be more sensitive?

In small turbines, admission valves are "balanced" so that the governor will be more sensitive.

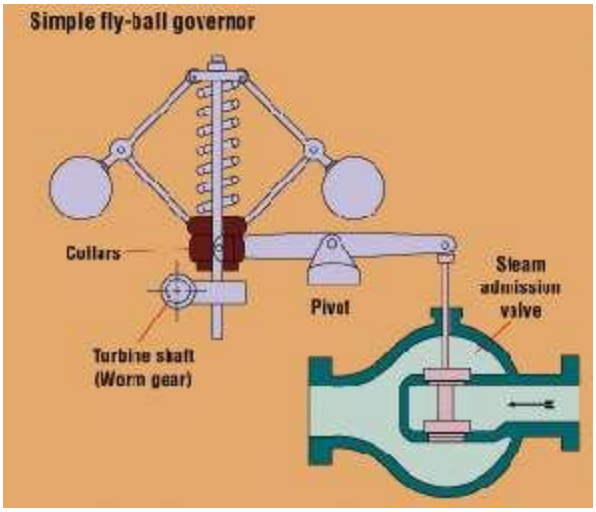



Figure 407. Flyball governor operating a balanced valve

## 9. How is a flyball governor used with a hydraulic control?

As the turbine speeds up, the weights are moved outward by centrifugal force, causing linkage to open a pilot valve that admits and releases oil on either side of a piston or on one side of a spring-loaded piston. The movement of the piston controls the steam valves.

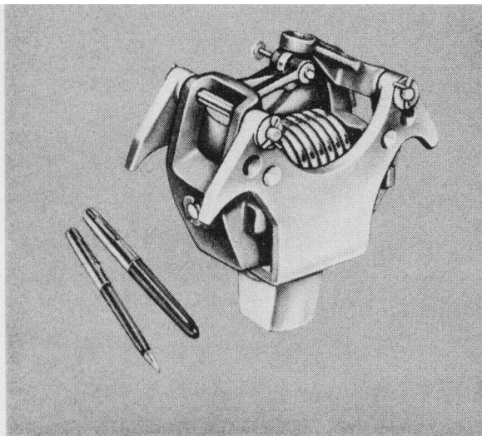


Figure 408. Flyweight governor note ink pens for size comparison

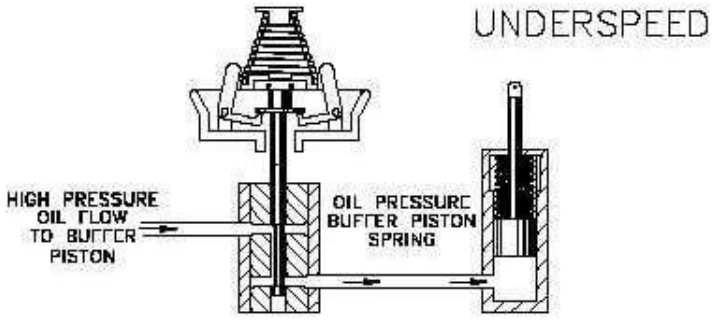



Figure 409. Hydraulic servo-motor operated by a flyweight governor increases the force necessary to operate a large valve while keeping the governor sensitive to speed change

## 10. Explain the servo-motor relay and how you adjust it.

A servo-motor relay is a device used to amplify the movement of the governor to operate the throttle valve. It meets the requirements of sensitivity and the need for development of large forces needed to open the valve. It is usually operated by a pilot valve. The pilot valves moves a hydraulic piston, this piston in turn moves a second pilot valve controlling the main power piston, also called the servo-motor. The steam valve is operated by the last piston. .High pressure oil from the main turbine oil pump is used as the operating force for the pilot and servo-motor, which is connected directly to steam valve.

The servo-motor is adjusted in the control room remotely, or by hand at the governor. As load changes are anticipated the speed changer is adjusted to allow the governor to operate in a different range of its rating.

The governor may be of the flyball or shaft driven impeller type.

*S&V page 241-246*

*D.E.S.C. Governors page 20-21*

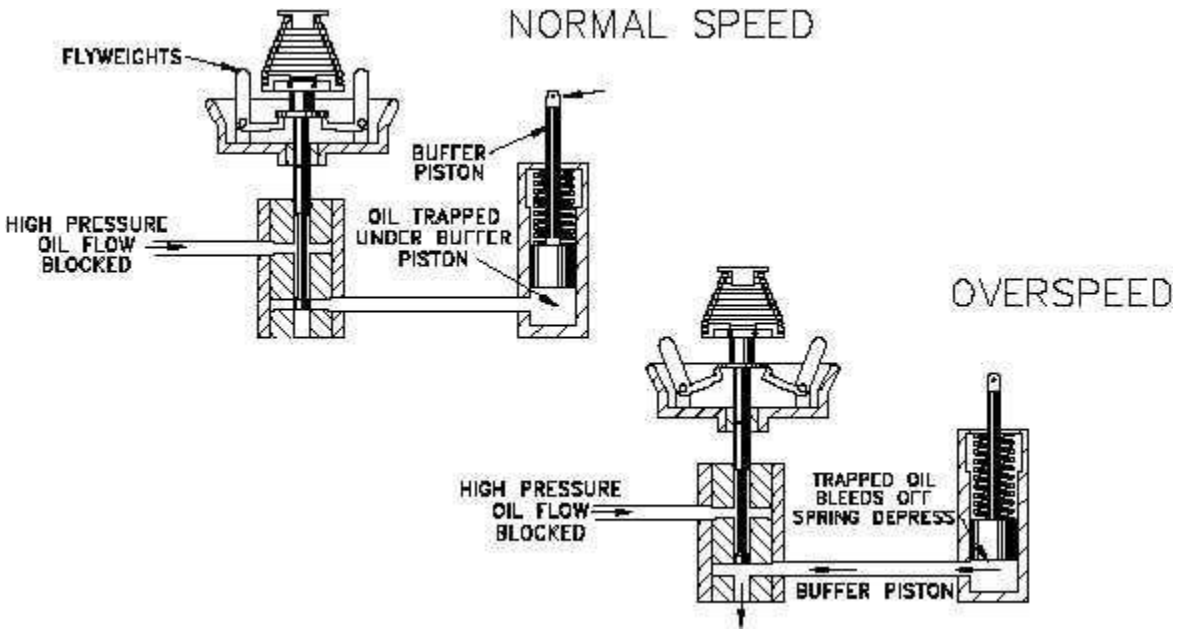



Figure 410. Servo-motor positions at normal speed and overspeed

## 11. What are the two main types of turbine governors?

Two main types of turbine governors are speed and functional. In speed governing, the steam flow varies with load change so that speed remains essentially constant. In functional governing, steam is controlled to maintain exhaust or extraction-steam pressure constant.

## 12. Explain each common application of steam turbine governors.

1. Straight-condensing or noncondensing: The governor responds to speed change induced by a load change. In turn the steam valves are opened or closed so that steam flow is changed to correspond to the load. The load and exhaust flow are variable, and inlet steam depends upon load.

2. Nonautomatic-extraction or bleeder: Load is variable. Exhaust flow depends upon inlet steam and the amount of bleeder steam; inlet steam depends upon the load.

3. Inlet-pressure regulation: Most commonly applied to condensing turbines. The governor maintains steam-chest pressure constant and in so doing permits the turbine to use all excess waste steam from other sources up to its capacity. The turbine operates in parallel with other units which are speed-governed and so obtains its speed control. The speed governor on the unit shown functions only when the speed varies beyond a given amount. The inlet steam flow is variable; the exhaust flow and load depend on inlet steam.

4. Back-pressure regulation: The governor functions like that in #3 except that back pressure is held constant. The exhaust flow is variable; inlet steam and load depend on exhaust flow.

5. Automatic-extraction or induction (one stage): This turbine supplies power load and process steam at a controlled pressure, or to use an available steam supply by mixing it with the main steam flow. Governor is a combination of speed governor and a pressure regulator. Speed change reacts to raise or lower both valves with no effect on extraction steam pressure. Load and extraction or induction steam flow are variable: inlet and exhaust depend on both load and process steam.

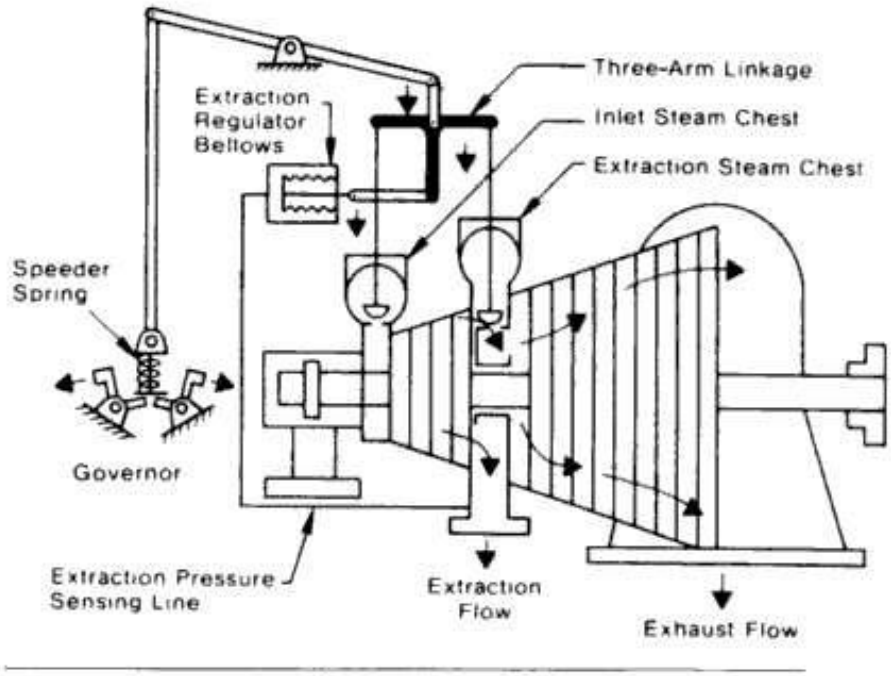



Figure 411. Automatic extraction governor

6. Automatic-extraction or induction (two-stage): Here the speed governor meets a load change by moving two three-arm levers to adjust position of all valves and changes load through steam flow. Pressure responsive governor maintains constant extraction pressure. Load and pressure controlled extraction flows are variable; inlet and exhaust depend upon former.

7. Automatic extraction with inlet pressure regulation: Governor gear permits a turbine to use and waste steam to the amount available and at same time to supply a controlled lower pressure extraction steam flow. Load and exhaust flow depend on inlet and extraction steam while the latter two

8. Automatic extraction with back pressure regulation: This governor is similar to #7 except that back pressure rather than inlet pressure is controlled together with extraction steam. Here the exhaust and extraction flows are variable with inlet steam flow and load depending on these former flows.

## 13. Structurally, steam turbine governors are divided into 3 general classes. What are they? What could be a 4th?

1) Hydraulic

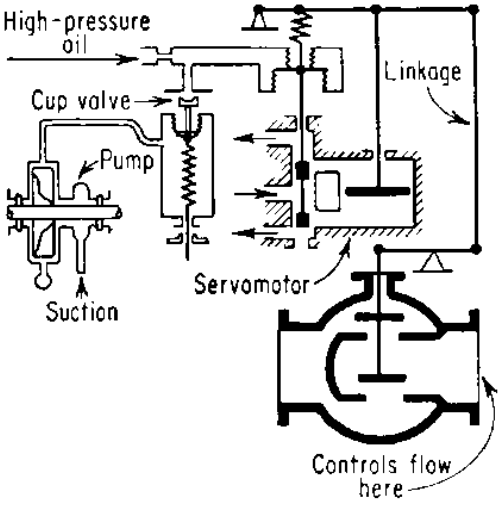



Figure 412. Hydraulic pump pressure is measured to determine speed and also used to operate the servomotor

## 14. Explain a completely hydraulic governor.

A completely hydraulic governor consists of two main parts:

1) The governor oil pump, pressure transformer, and speed changer.

2)The servomotor relay and power piston operating the governor valves. For a load decrease, which means an increase of turbine speed, the governor oil pump discharge pressure will increase and this will compress the bellows and raise the oil cup. This chokes off oil flow from the main oil pump through the line above the cup and the oil pressure in the line increases. This increased secondary oil pressure acts on the oil cup and stops its motion and also reacts through a small piston causing it to move downward. Its valve movement is stopped by tension in the follow-up spring. The cup valve moves down and the oil pressure above the relay increases and moves the relay down. Pilot then allows oil to flow under power piston and releases oil from above it. Linkages close steam valves.

As speed of turbine varies the discharge oil pressure changes. The governor is sensitive since the oil pressure varies as the square of the turbine speed.

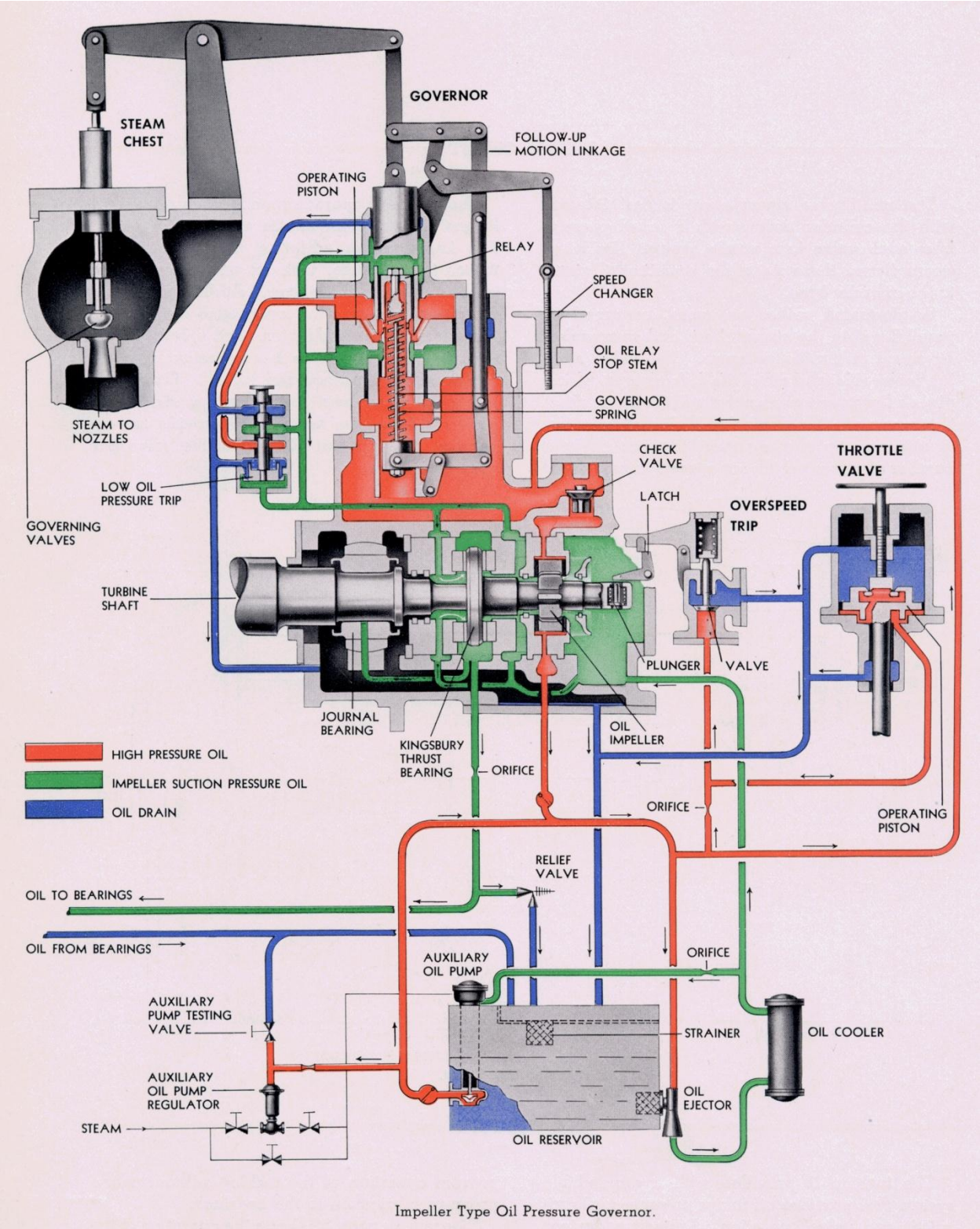



Figure 413. Hydraulic governor. Find the oil impeller in the above picture. The pressure generated by the oil impeller determines the speed at which the turbine will run.

2) Mechanical

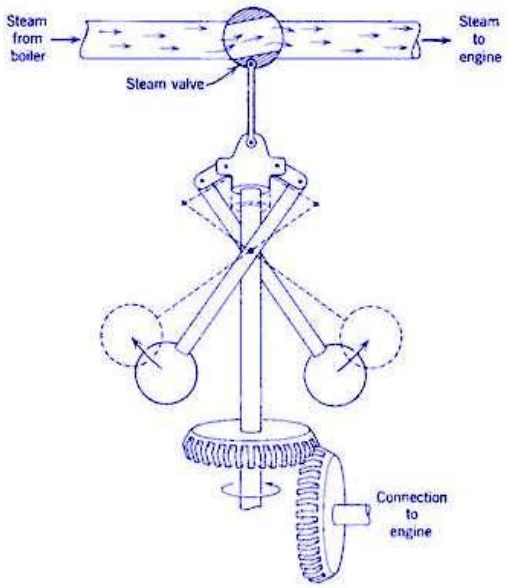



Figure 414. Simple mechanical governor

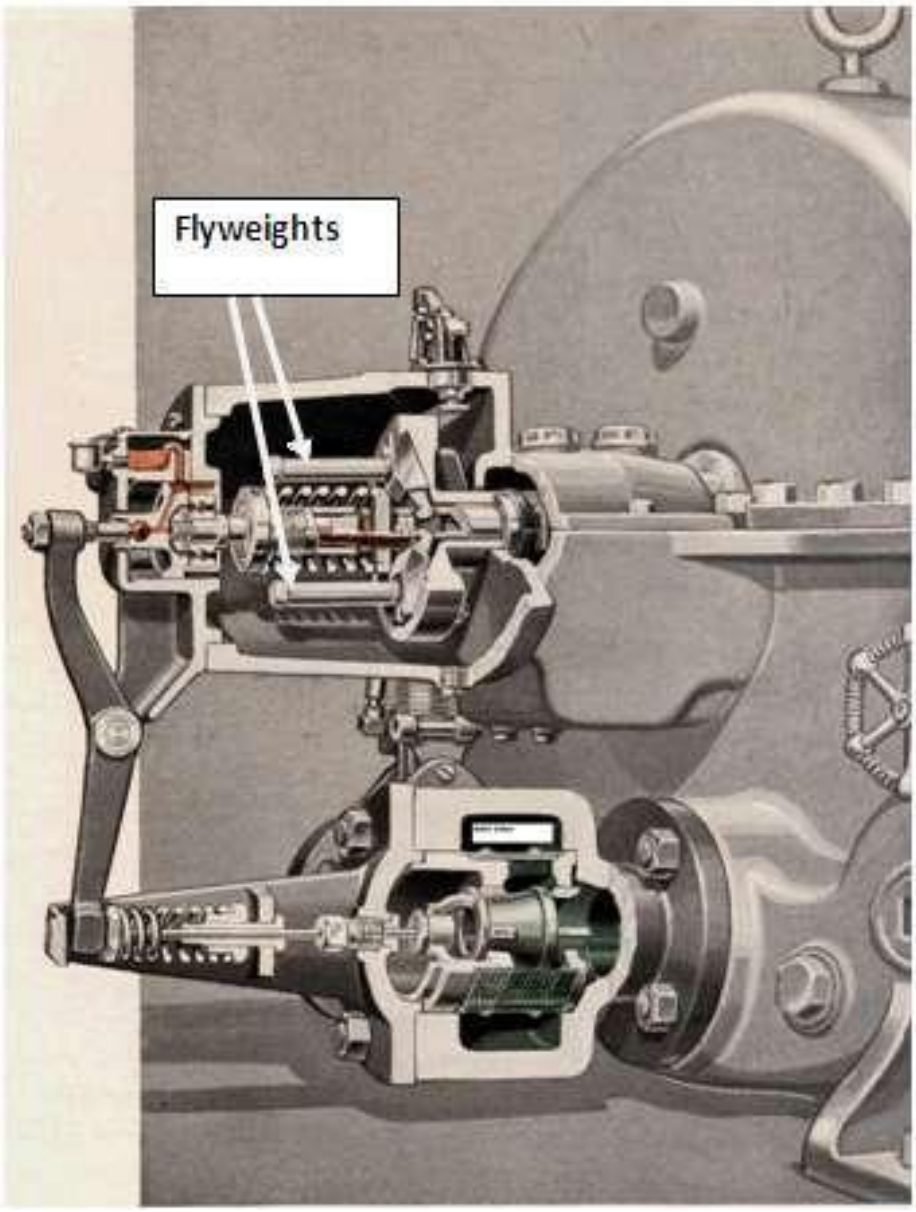



Figure 415. Mechanical governor on a small turbine

3) Electrical

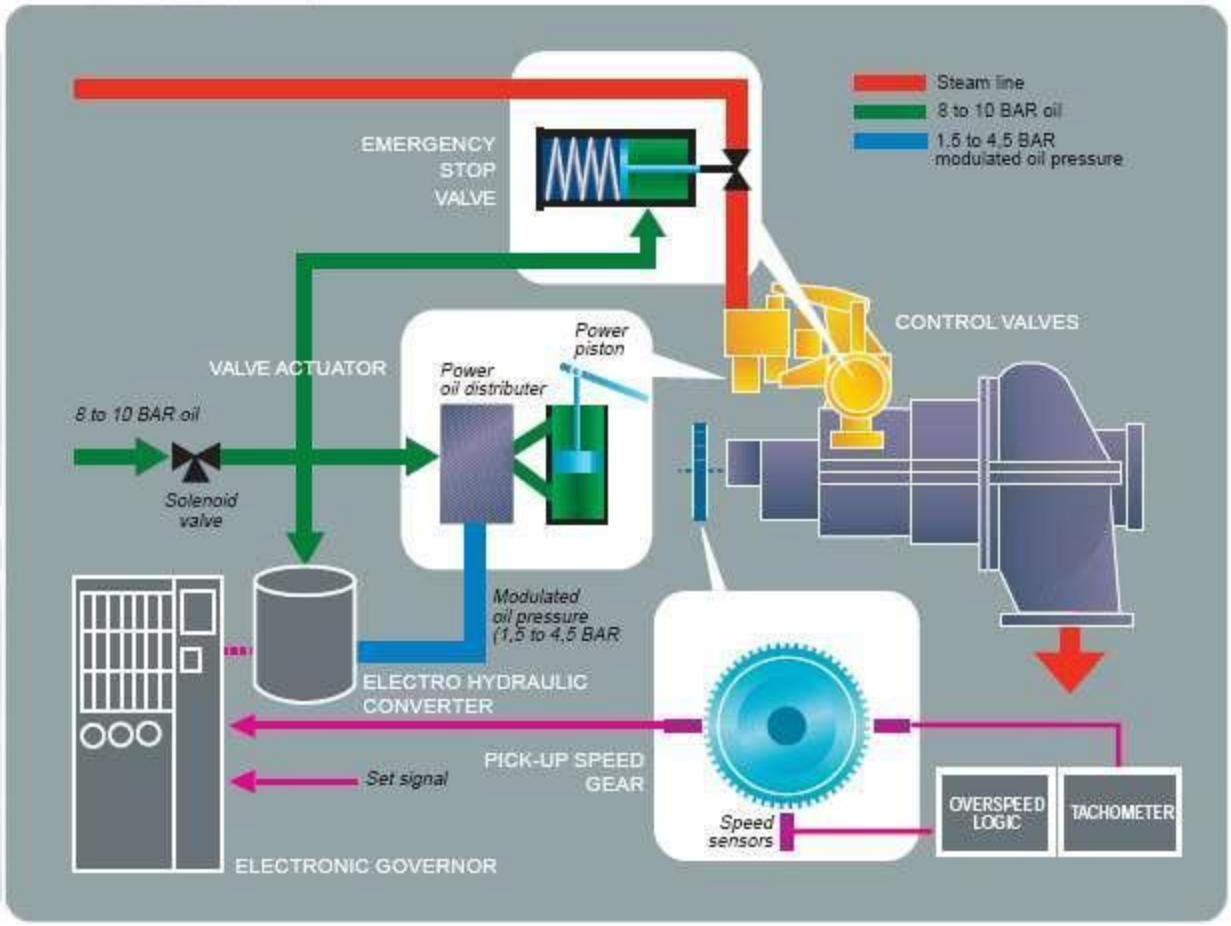



Figure 416. Electrical governor

## 15. What can you say about an electric governor?

Electric governors at present are applied primarily to turbines of about 750 to 1000 RPM driving paper and textile machinery. It can operate overspeed ranges as large as 30 to 1, and at any speed the changes setting is practically isochronous. Seldom used but gives very good speed regulation.

4) A combination of these.

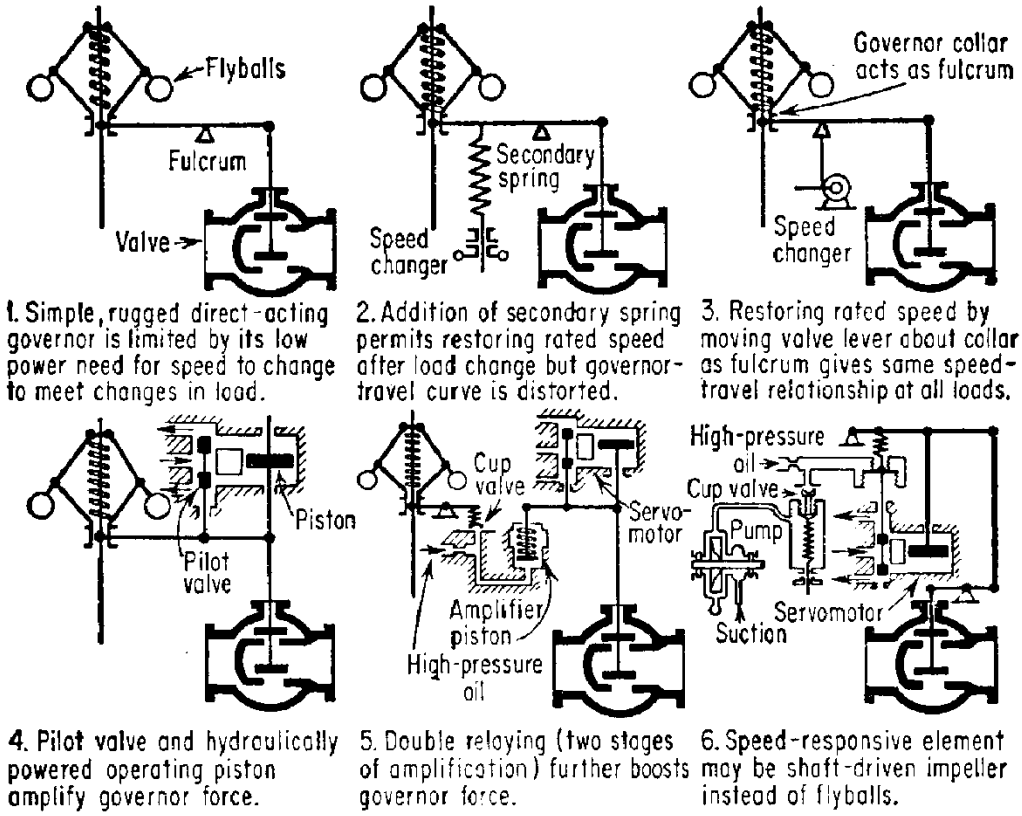

Flyballs
Fulcrum
Valve
1. Simple, rugged direct-acting governor is limited by its low power need for speed to change to meet changes in load.
Secondary spring
Speed changer
2. Addition of secondary spring permits restoring rated speed after load change but governor-travel curve is distorted.
Governor collar acts as fulcrum
Speed changer
3. Restoring rated speed by moving valve lever about collar as fulcrum gives same speed-travel relationship at all loads.
Piston
Pilot valve
4. Pilot valve and hydraulically powered operating piston amplify governor force.
Cup valve
Servo-motor
Amplifier piston
High-pressure oil
5. Double relaying (two stages of amplification) further boosts governor force.
High-pressure oil
Cup valve
Pump
Servomotor
Suction
6. Speed-responsive element may be shaft-driven impeller instead of flyballs.

Figure 417. A variety of governor types

Figure 418. Flyweight governor and parts of the servomotor

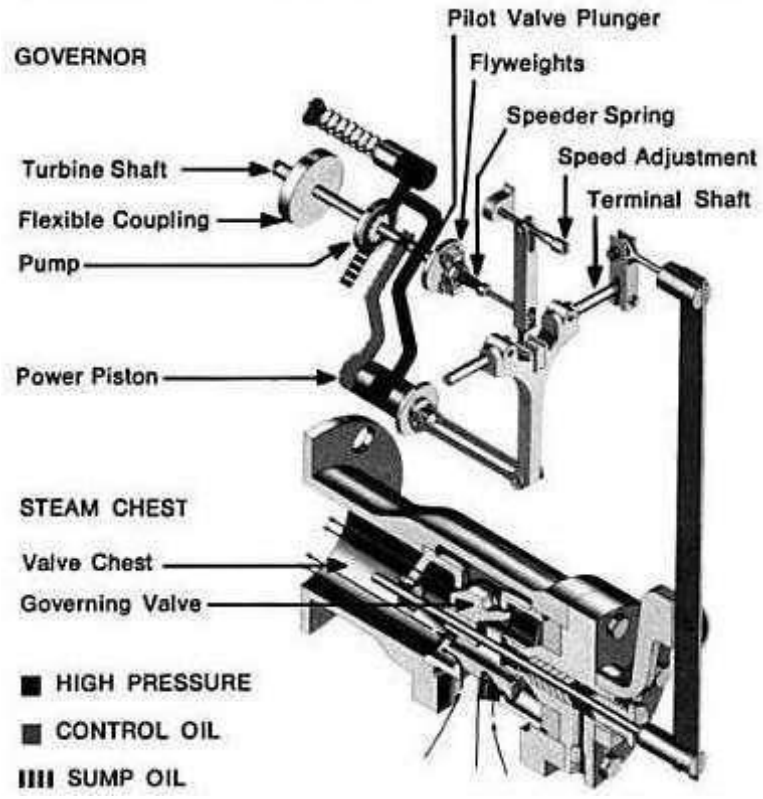



Figure 419. Servomotor governor

## 16. Explain the difference between the speed changer and the load changer.

The speed changer is used during start up to control speed of the turbine for warm up and is used during synchronizing to match speed of the generator to grid frequency. After synchronization, the speed changer becomes a load changer and is immediately used to put a load on the turbine to prevent it from motorizing the generator. Motorizing a generator in a small or medium plant not hooked to an electrical grid can overload the other generators and trip them off the line. This leads to a "black start" and will normally lead to you seeking other employment.

The governor is used to regulate the speed of the turbine during synchronization only. System frequency determines the turbine speed when on the electrical grid and the governor is then used only to vary the load on the turbine to match electrical demand. As load increases the turbine will start to slow down and the governor will open steam valves to maintain the correct speed. (3600 revolutions per minute on a 2 pole generator in the USA). Adjusting the load changer will determine how much of the electrical load that particular turbine will carry

*D.E.S.C. Turbine Operation page 6, D.E.S.C. Governors page 20-21*

1) When the unit is not connected to a grid (particularly a large, or infinite, grid) increasing the energy being admitted to the prime mover will cause the prime mover to increase speed.

When the unit is connected to a grid, increasing the energy being admitted to the prime mover will NOT result in a speed increase. It WILL result in an increase in the amperage of the generator. In other words, the power output of the generator will increase. The extra torque which would cause the unit to increase its speed when not connected to the grid gets converted by the generator into additional power output (amps).

2) If the prime mover and generator are directly coupled, in other words, there is no reduction gear or speed increaser between the prime mover and the generator, the prime mover and the generator will turn at the same speed as the generator.

Even if there is some gear box (reduction or speed increaser), the speed of the prime mover is still directly proportional to the speed of the generator rotor. And the speed of the generator rotor is directly proportional to the frequency of the grid to which the generator is connected.

The frequency of a generator is directly proportional to the product of the number of poles of the generator times the speed of the rotor (in RPM), divided by 120: Frequency = (P*N)/120. If a grid is operating at 60 Hz and the generator connected to the grid has two poles, the speed of the generator rotor will be 3600 RPM (N = (120*60)/2).

3) AC generators are usually synchronous generators. Synchronous means they are locked in synchronism with the frequency of the grid to which they are connected, especially if the grid is very large, or, infinite. Suppose a 60 MW steam turbine is connected in parallel with other generators on a grid with a total output of 6,000 MW. The little 60 MW steam turbine isn't going to make all the other turbines speed up or slow down detectably as the prime mover's energy is increased or decreased--there's just too much inertia to overcome.

Also, there should be operators and control systems somewhere on the grid which would decrease the load of one or more units to maintain the grid frequency at rated. As units are loaded by their operators they actually accept some of the load from the grid. If enough units are loaded without some units being unloaded equally, the grid frequency will begin to increase.

## 17. How do shift load from one turbine to another?

According to the Engineer at Trenton Channel Plant load can be shifted by manipulating the load controller which has the ability to reset the governor. Usually if 2 turbines are on line, one is operated at or near full capacity while the other is used to handle the remaining load. Load is not shared 50/50 between two turbines.

*Edison Plant Tour, D.E.S.C. Governors page 20 & 21*

## 18. What is % of speed regulation on a small turbine?

The change in speed of a turbine from no load to full load divided by full load is known as speed regulation. A turbine with a full load speed of 1764 RPM and a no load speed of 1800 RPM would have a change of 36 RPM or regulation of 2%.

*W. & L. page 458.*

2% above or below normal is allowable for small turbines.

*Kents Turbine Section page 8-47 11th Edition*

2% over or under is allowable for electric lighting service.

*W. & L. page 458 , Kents pages 8-47 & 8-48*

## 19. At what speed does the governor come into play on an electrical generating turbine?

The governor starts at:

1700 RPM on a 1800 RPM unit.

3400 RPM on a 3600 RPM unit.

## 20. What part of the turbine is the tachometer measuring the speed of?

The rotor

"The speed of rotation of the rotor is generally determined by a tachometer"

*Croft Steam Turbines page 261*

Figure 420. Reed tachometer

Figure 421. Woodward governor with LCD tachometer display

## 21. Is better control of turbine speed obtained with hand control, throttling the throttle valve, or by governor control only?

Speed regulation is best controlled through the use of a governor. However, it is regulated through the speed changer during start-up. During operation the speed of the governor is controlled by the frequency of the grid and the speed changer becomes the load changer.

Throttling of the throttle valve is used on some turbines but does not provide good control. This type control is found on impulse units.

Hand control is used on very small turbines of the single stage impulse type.

Large reaction turbines require that steam be admitted to 100% of the periphery. The only means of controlling the output or the speed of a pure reaction turbine is to raise and lower the pressure of the steam entering the 1st. stage blading as a result of opening and closing the governor controlled inlet valve.

*D.E.S.C. Turbines*

Figure 422. Woodward PGPL governor on small turbine

## 22. What is "speed droop"?

Governors with speed droop usually have a speed changer which can be adjusted after a load change to return the unit to normal speed. Speed droop is speed change with load change.

With synchronous generators. Their speed is a function of their frequency (or, it can also be said that their frequency is a function of their speed). But because they are synchronous generators no generator can go faster or slower than the speed that is dictated by the frequency. And, because they are all connected together and their rotors are locked into synchronism with each other (magnetically), the prime movers which are mechanically coupled to the generators can't change their speeds either.

When a prime mover driving a synchronous generator is connected to a grid with other generators and their prime movers, particularly a large or "infinite" grid, the frequency of the generator is controlled by the frequency of the grid. And, since the speed of the prime mover that is mechanically coupled is a function of the frequency of the generator, then the speed of the prime mover is fixed.

No synchronous generator (nor its prime mover) can run faster or slower than the other synchronous generators (and their prime movers) on the grid. It's just not physically possible for one generator to be running at 60.134 Hz and another to be running at 62.27 Hz, and still another to be running at 59.65 Hz if they are all connected to the same grid which is operating at 60.001 Hz. It just can't happen.

When there's just one machine driving a load independent of any other machine, the prime mover control system is usually operating in Isochronous Speed Control, not in Droop Speed Control.

To make a prime mover (which is providing the torque input that the generator is converting to amps that is being converted to torque by motors which are also connected to the grid) stably control its power output while connected in parallel with other generators and prime movers on a grid, the control systems employ straight proportional control. And that proportional control is called droop speed control.

Droop speed control looks at a prime mover's speed reference and its actual speed, which is a function of the grid frequency.

To increase the power output, the speed reference is increased. But, since the speed can't actually change the increased error between reference and actual speed is converted to increased fuel flow. That increased fuel flow, which would tend to increase the speed, which can't increase appreciably, is still extra torque. And the generator converts that extra torque into more amps. All of this is done very smoothly and all the prime movers and their generators behave nicely and work together to provide the load. If the "load" on the generator is to be increased, then the turbine speed reference is increased again, the error between the actual speed and the speed reference increases again, which increases the fuel flow which increases the torque which increases the amps.

When turbine operators are watching the watt meter and turning the governor handle in the Raise direction to get the watt meter reading to increase, they aren't changing the watt reference they are changing the turbine speed reference.

**23. How can the speed variation be reduced by making a governor droop adjustment?**
If the internal droop setting is increased, the speed variation will reduce.

**24. In recommended specifications for speed governing of steam turbines "rated power output" is stated on a turbine nameplate in what manner?**

"Rated power output" is stated on turbine nameplate in kilowatts.

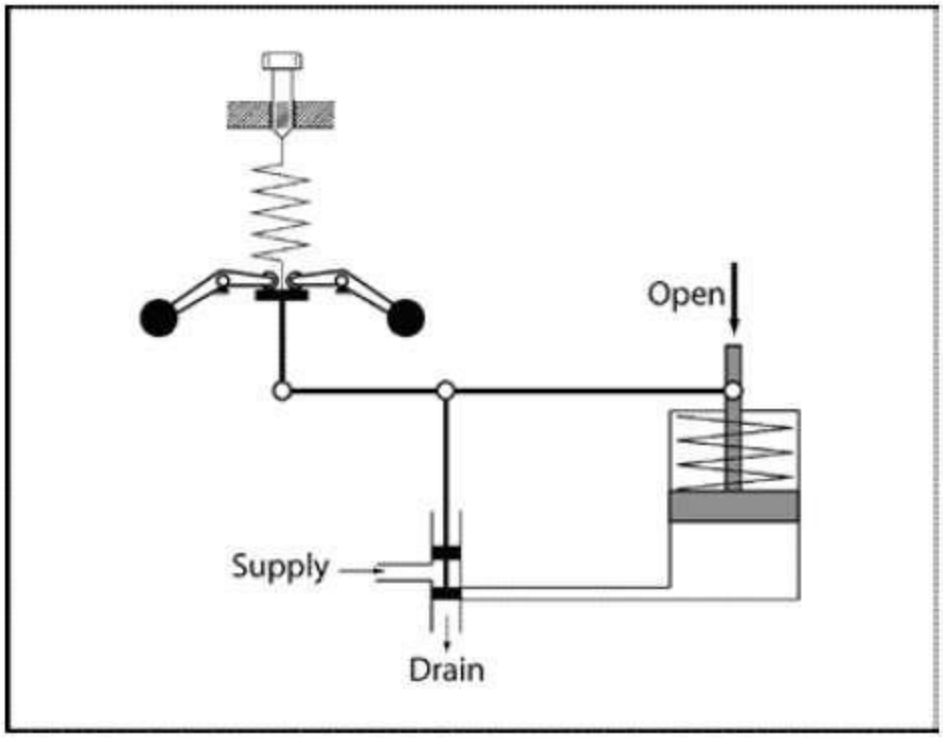



Figure 423. *Droop governor*

**25. What is a "travel governor"?**

A "travel governor" is one where the weights have to be moved to change the governing valves to a different steam-flow position for each load change, while turbine speed is constant.

*S&V page 258*

Even with a perfect governor valve, the relationship between the speed and steam flow is far from ideal. Most governors employ a speed changer to eliminate most of the discrepancy. Using a speed changer moves the weights to a different flow position to maintain the same turbine speed. This is why it is called a “travel governor”.

*Instrument and Control Manual for Operating Engineers by Eugene Feller pages 323-325*

## 26. Explain a "strap governor".

Strap governor has sliding collar replaced by a metal strap. Very small movement is caused by elastic deformation of the strap metal under the centrifugal action of the weights.

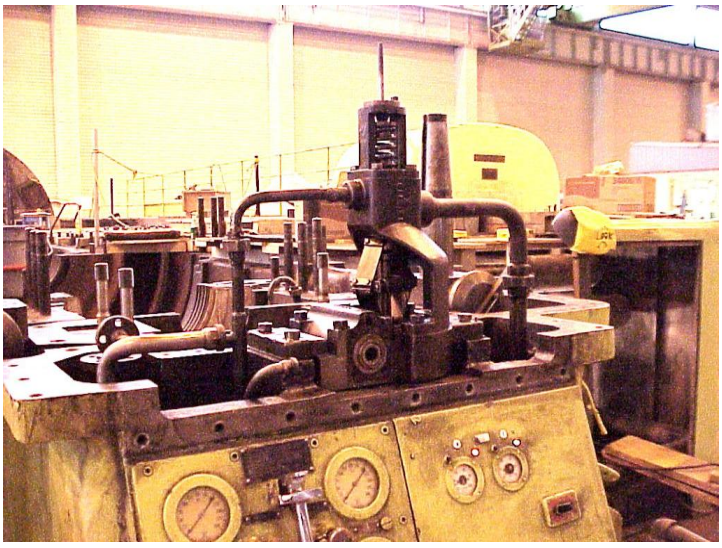


Figure 424. Strap governor inside turbine casing

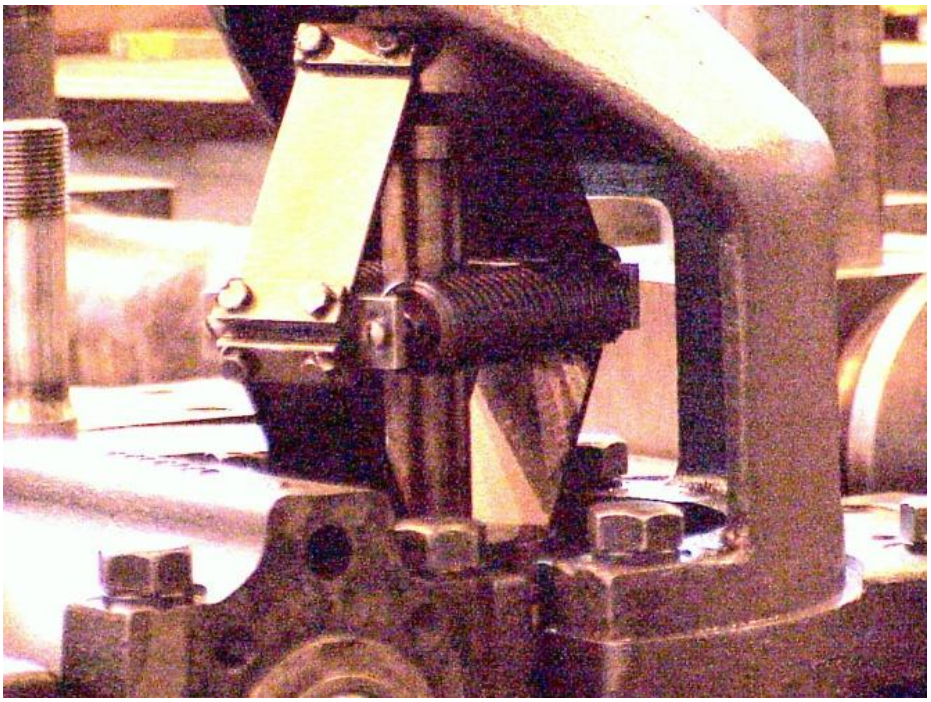


Figure 425. Close-up of strap governor

With flyball governing, some friction remained in the system. Engineers went back to the speed-sensitive element itself and substituted a metal strap carrying centrifugal weights for the flyballs and sliding collar. In principle, the two devices are identical except that the strap governor produces forces entirely by an elastic change and hence is frictionless. A strap governor can be considered a “non-travel” governor

*Instrument and Control Manual for Operating Engineers by Eugene Feller page 328*

## 27. What is meant by "rated upon zero dead band"?

Dead band is the total magnitude of the sustained speed change within which there is no resulting measurable change in position of the governor control valves.

Dead band is a characteristic of the speed governing system that is commonly known as Wander. It is the insensitivity of the speed governing system that is defined as the total speed change during which there is no change in the position of the governing valves to compensate for the speed change

*Steam Turbines, designs, applications and rerating by Heinz Bloch page 141*

Steam Turbine Control
Many shell mounted control valves are modulated by a rack and cam arrangement. This valve operating method utilizes a common hydraulic cylinder to lift a rack of four to nine poppet valves in sequence. A fulcrum lever is used to multiply actuator force. Exlar provided a direct replacement of the hydraulic cylinder with an electric servo actuator and positioner.

Figure 426. Exlar actuator replaced the Original Equipment Manufacturers actuator with their actuator

100% Torque Available all the time. Full torque means almost zero deadband. Friction in the valve stem is no problem for the Exlar actuator. Current is always available to the actuator — so it will hold its position no matter what. This provides excellent process loop control.

## 28. What is an isochronous governor?

A neutral or isochronous governor is one which, at a certain speed, assumes, indifferently, any position throughout its range. If the centrifugal force and the centripetal force change at the same rate, the governor is neutral or isochronous. Governors are frequently called "isochronous" (which means equal speed) when they are not truly so. A truly isochronous governor would also be useless for engineering because it would change in position as much for a slight change in load as it would for a large one.

*Croft Steam Engine Principles and Practice 2nd Ed. p. 204 Sec.220 and Note*

A turbine governor designed to maintain constant speed at all steady turbine loads within the capacity of the unit is an "isochronous" governor or one having zero speed droop.

## 29. Extraction or induction governing systems must provide for three possible conditions. What are they?

Extraction or induction governing systems must provide for three possible conditions:

1.) A change in load only.

2.) A change in extraction or induction steam only.

3.) A possible change in both load and steam flow.

## 30. What are the primary elements of the double extraction flow system? Control action is due principally to what?

Primary elements of the double extraction flow system are:

1.) Speed governor.

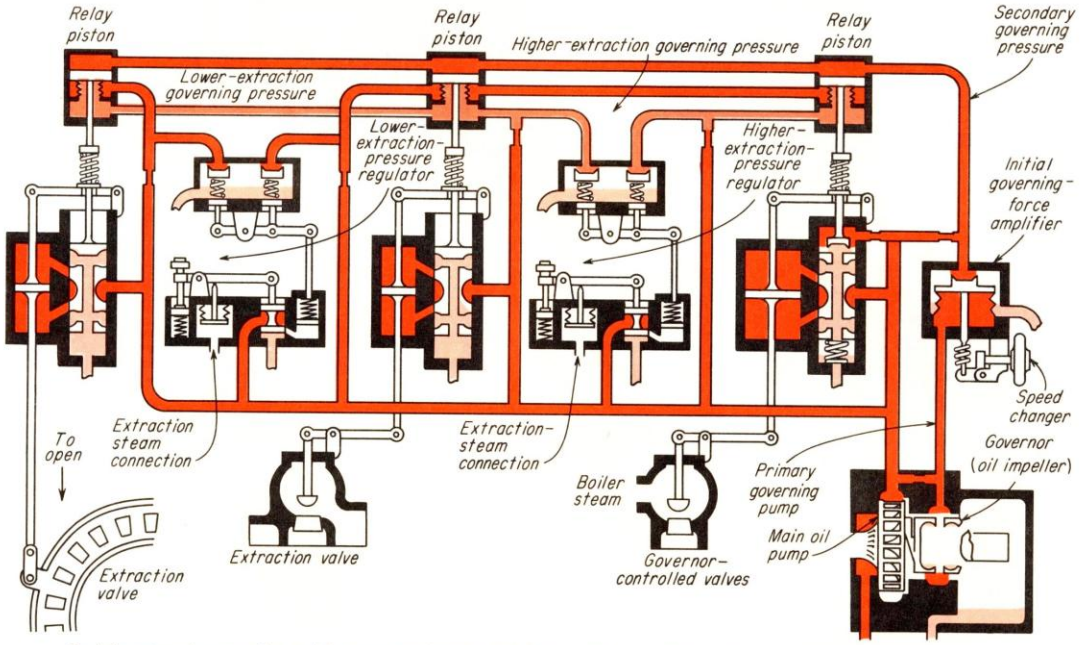
2.) Extraction pressure regulator interconnected with the speed governor

3.) Three servomotors operating governor and pressure valves.

4.) Servomotor pilot valves.

Control is due principally to the action of the double-extractive pressure regulator.

Figure 427.




Double-automatic-extraction turbine uses combination of three signals on three relay pistons to hold constant pressure at each of its extraction openings and maintain a constant shaft speed

## 31. What happens if load changes with no change in extraction flow? If there is a change of extraction in 1st stage, but no load change in the 2nd stage?

In case of a load change with no change in the extractor steam flow, the operation is as follows: The centrifugal weights of speed governor react through a governor servomotor which transmits the same motion with increased force to all relief valves through the set of springs loaded by the governor These relief valves then cause both main inlet and the extraction valves to change their position a given amount. Hence, load change is provided for with no change in extraction pressure.

In case of change of extraction from 1st stage, but no load or 2nd stage change, the operation is as follows: Change in extraction causes change in stage pressure. The extraction pressure regulator responds and changes, spring loadings on the three relief valves which causes the governor controlled valves and the two pressure-controlled valves to change slightly. The result is steam flow to turbine is changed and restores 1st extraction pressure to normal.

## 32. What is a multi-port governor valve? Why is it used?

In large turbines, a valve controls steam flow to groups of nozzles. The number of open valves controls the number of nozzles in use according to the load. A bar-lift or cam arrangement operated by the governor opens and closes these valves in sequence. Such a device is a multi-port valve. Using nozzles at full steam pressure is more efficient than throttling the steam.

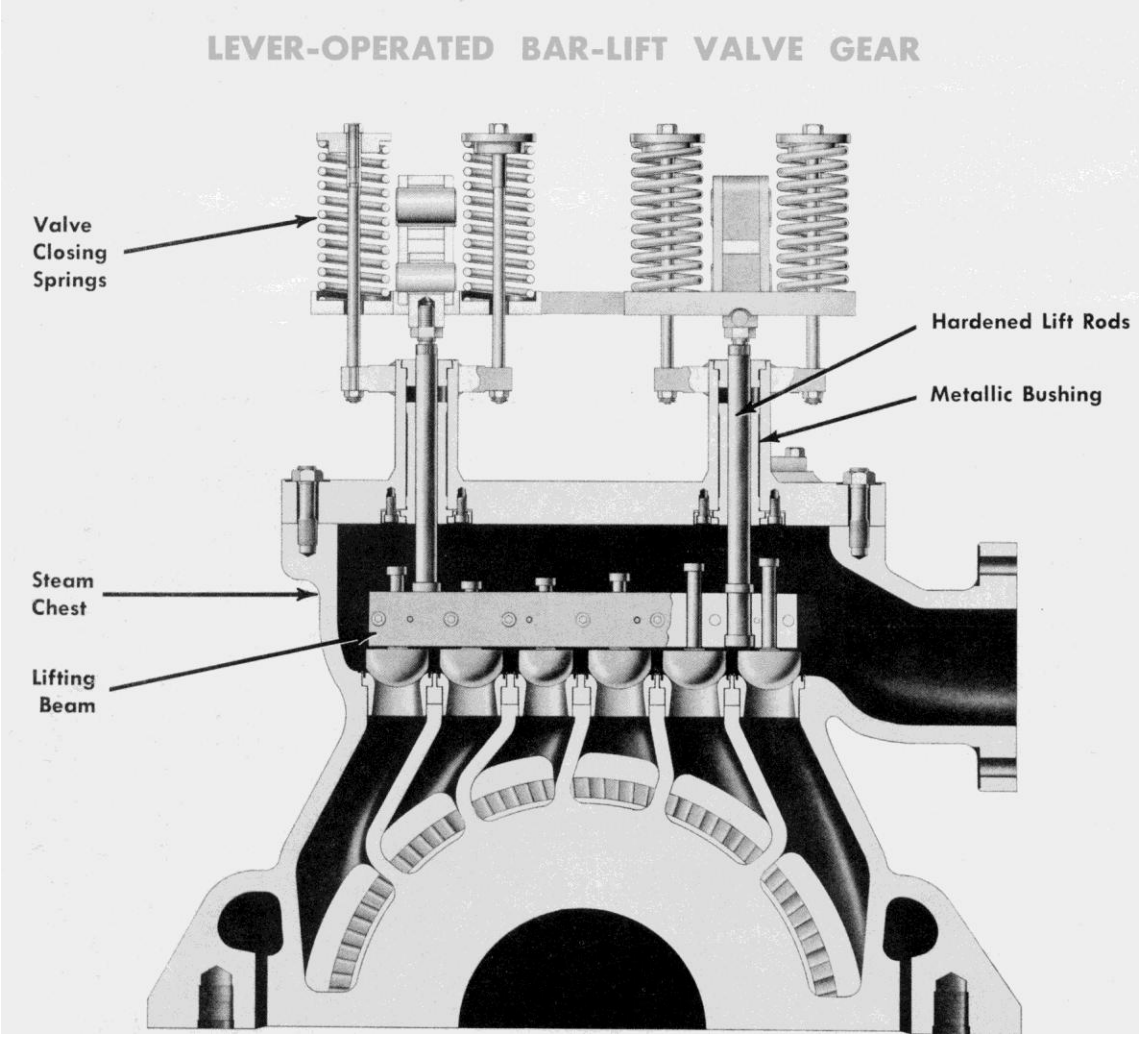



Figure 428. Multiport governor valves on bar lift mechanism

## 33. What basic governor troubles are apt to occur?

Hunting. Hunting is the alternate speeding and slowing of the turbine, which means that the governor is too sensitive to load changes.

Sticking. Sticking is the failure to control speed, allowing the turbine to Overspeed or slow down. This means that the governor is not sensitive to load changes or parts are binding or worn.

## 34. What are reasons that cause a governor to hunt?

A governor hunts when, in changing from one load to another, it has a tendency to go too far due to the momentum of its parts.

*Croft Steam Engine Principles and Practice 2nd Ed. page 210*

Dashpots are frequently used in connection with turbine governors. They are used to keep the governor from overtraveling because of the weight of the governor parts. When a governor adjusts the speed of a turbine and makes a change that an adjustment in the opposite direction is immediately necessary, the governor is said to "hunt" or overtravel. In other cases dashpots are used to prevent the governor from operating too quickly. Friction or lost motion in the valve mechanism or, in some cases, too heavy or improperly installed dashpots will cause a turbine to "hunt". Rapid changes in speed and the corresponding variation in load are referred to as surges.

*Woodruff & Lammers page 496*

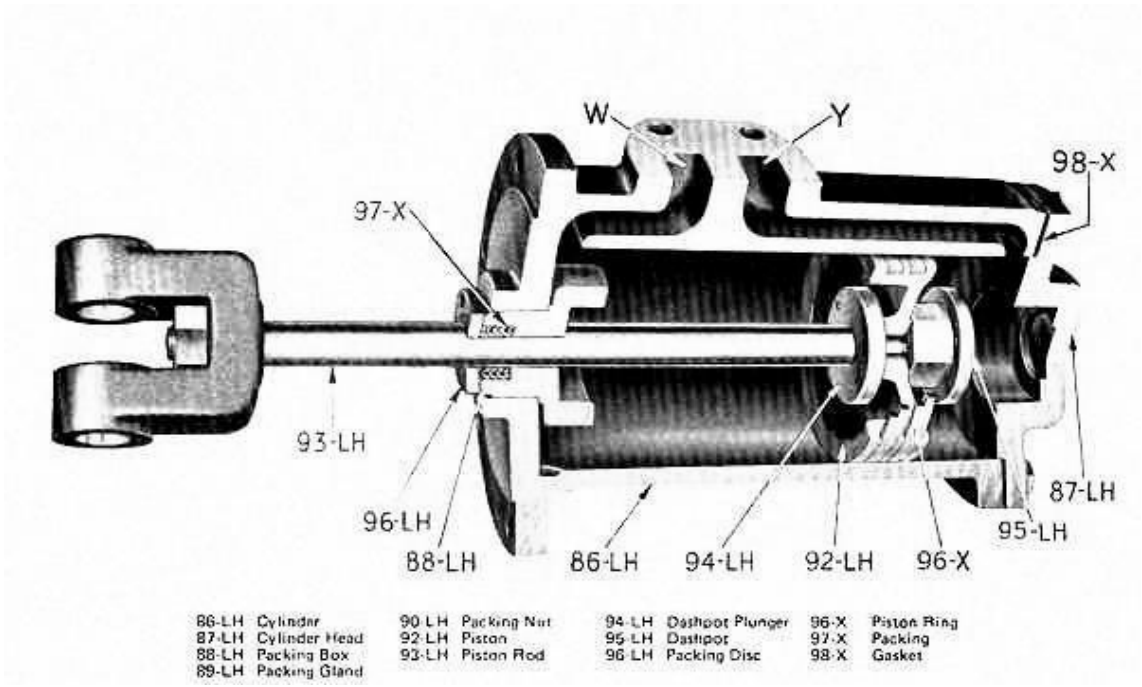



Figure 429. Dashpot used on turbine governors

### 35. How does improper governor lubrication arise and what effect does it have?

In the event of low governor oil level or if the oil is dirty or foamy, it will cause improper governor lubrication.

### 36. What is the remedy to it?

The dirty or foamy lube oil should be drained off, governor should be flushed and refilled with a fresh charge of proper oil. In the event of low level, the level should be built up by make- up lube oil

### 37. What factors contribute to excessive speed variation of the turbine?

Improper governor droop adjustment.

Improper governor lubrication.

Throttle assembly friction.

Friction in stuffing box.

High inlet steam pressure and light load.

Rapidly varying load.

### 38. What can excessive speed of the turbine lead to?

Complete destruction of the turbine

Destructive Overspeed of 25 MW Steam Turbine Generator

Figure 430.

**39. What is Boiler Follow mode, Turbine follow mode and Coordinated control used in Power Plants and what is the difference between these three?**

Boiler Follow Mode: The boiler is divorced from the generation control, which means the steam turbine utilizes stored energy in the boiler to provide immediate load response. The boiler must then change firing rate to bring pressure back to setpoint.

Turbine Follow Mode: Turbine control valves maintain a set pressure while the boiler fires to maintain load. Drawback here is a slower generation response. There are variations with this scheme, in that the turbine control valves can be fully opened at higher loads to minimize the energy penalty associated with the DP loss across them. In that case, it has been called sliding-pressure control, or even cascade control.

Coordinated Control: In general, you provide various logic schemes to move the steam turbine valves for quick load response, as well as fire the boiler for the anticipated energy requirements of the boiler (generally via an energy balance equation). *Arthur Mayclin, Chief Instrumentation and Controls Engineer at Calpine Power*

Turbine-Following Mode. In many ways, this is my favorite plant operating mode, because it is the easiest to tune. It also offers a good strong safety net to operators in times of crisis. In turbine-following mode the boiler master is in manual and the turbine master is in automatic mode. The turbine master controls throttle pressure by modulating the turbine governor valves. Megawatts are then produced in the generator and pushed to the grid as a function of the boiler load.

Compared to the slow and sometimes lumbering response of the boiler, turbine response is usually fast and agile. Proportional gains are usually moderately large, and the integral action can be quite fast. Although adaptive tuning is possible, there usually isn't the need for this; many units use only one value for the proportional and/or the integral gain. Also, the need for a feedforward is minimal. The turbine governor valves operate as one large pressure control valve that can easily control throttle pressure when the control loops are well-tuned.

Turbine-following mode is also a favorite among powerplant operators. If the plant is in coordinated mode, and the unit starts to go out of control for almost any reason, operators simply have to put the boiler master into manual. Immediately, the controls will automatically default to turbine-following mode. The valves open or close, as necessary to control the main steam pressure. Meanwhile, because the firing rate has steadied, the boiler controls will soon settle out.

*Tim Leopold, ABB Inc*

Figure 431. Governor and field excitation controls

## 40. Governor and Field Excitation Controls

Basically, the left motor control changes generator loads through the use of a DC motor attached to a set of steam admission valves on the turbine, as well as controlling the speed of the unit before it is synchronized with the system (connected to the grid). The two white lights associated with this control indicate low and high limits. Both lights lit (shown here) indicate the control is somewhere in between.

AC generators require DC current to energize its magnetic field. The right rheostat manually controls this DC field current. The blue lights associated with this control indicate low and high limits and the white light designates that the exciter output is in operational range when the generator voltage reaches approximately 13,800 volts. The left blue light indicates this switch has reached its low limit.

*Gorsuch Station- Former UCC Marietta Ohio.*

# Overspeed Trip

## 41. How many governors are needed for safe turbine operation? Why?

Two independent governors are needed for safe turbine operation. One is an overspeed or emergency trip that shuts off the steam at 10 percent above running speed (maximum speed). The second, or main governor, usually controls speed at a constant rate; however, many applications have variable speed control.

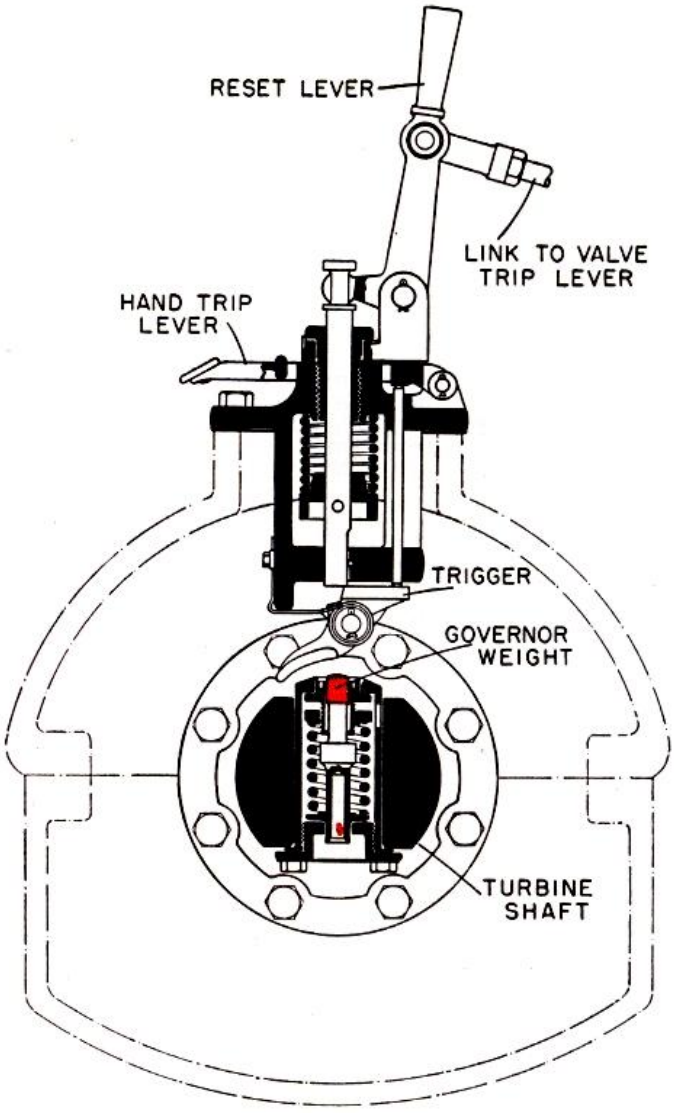



Figure 432. In case of overspeed, centrifugal force causes the governor weight to move out from its normal position in the turbine shaft and engage a trigger releasing a spring loaded linkage to operate the emergency trip. The hand trip lever is used to manually trip the valve closed. The reset lever will allow the hand trip lever to be repositioned on its catch and trigger. The main steam valve to the turbine is closed prior to resetting.

## 42. What is the danger of overspeeding? Explain fully.

Overspeeding is dangerous because centrifugal forces would exceed the stresses that the rotor could withstand, with the result that the rotor would be torn apart, literally explode, with great danger to everything in the vicinity

BOWLING GREEN FLORIDA— April 14th 2007, A massive explosion occurred Saturday night at Unit 3 of the Payne Creek Generating Station, severely damaging its steam turbine and generator, according to a spokesman from the Seminole Electric Cooperative, which owns the plant.

There were no injuries and no power was disrupted by the explosion. Seminole Electric is a cooperative of 10 member systems of which Wauchula-based Peace River Electric Cooperative (PRECO) is one.

The 810-megawatt power plant, located along C.R. 663 near the Polk County line, was rendered inoperable as firefighters from Bartow, Fort Meade, Avon Park and Hardee County swarmed the fire. Deputy Chief Dan Harshburger from Hardee County Fire Rescue said there were no injuries related to the explosion while it was still being investigated, but the damage was extraordinary from his perspective.

"I can't even describe it," Harshburger said. "There was one piece of the turbine... maybe three or four tons, and it blew out the roof and it landed in another building 200 feet away. There was shrapnel out everywhere."

Jeff Fela, spokesman for the Seminole Electric Cooperative, said the cooperative has been purchasing power from other sources while they are accessing the damages. The cooperative could possibly run parts of the plant after the assessments are completed, he added.

Fela said the steam turbines explosion happened around 8:30 p.m. Saturday, and a fire took place after the explosion. In the plant, each of the three main units fills two three-story rooms. The second floor of the generator and turbine rooms for Unit 3 collapsed in the incident.

Harshburger said the plant turbines had generated a few fires in the past, "but nowhere near like this."

Figure 433. Payne Creek Generating Station

Figure 434. Generating Station Fire, Not at Payne Creek

## 43. What is an overspeed safety governor?

The emergency or overspeed governor protects the turbine against excessive overspeed in case of failure of the operating governor. At 10% overspeed it automatically trips either the stop valve, a separate overspeed valve or a combination of these.

It is reset manually once turbine falls back to normal speed.

*D.E.S.C. Turbine Operation page 4 & 5*

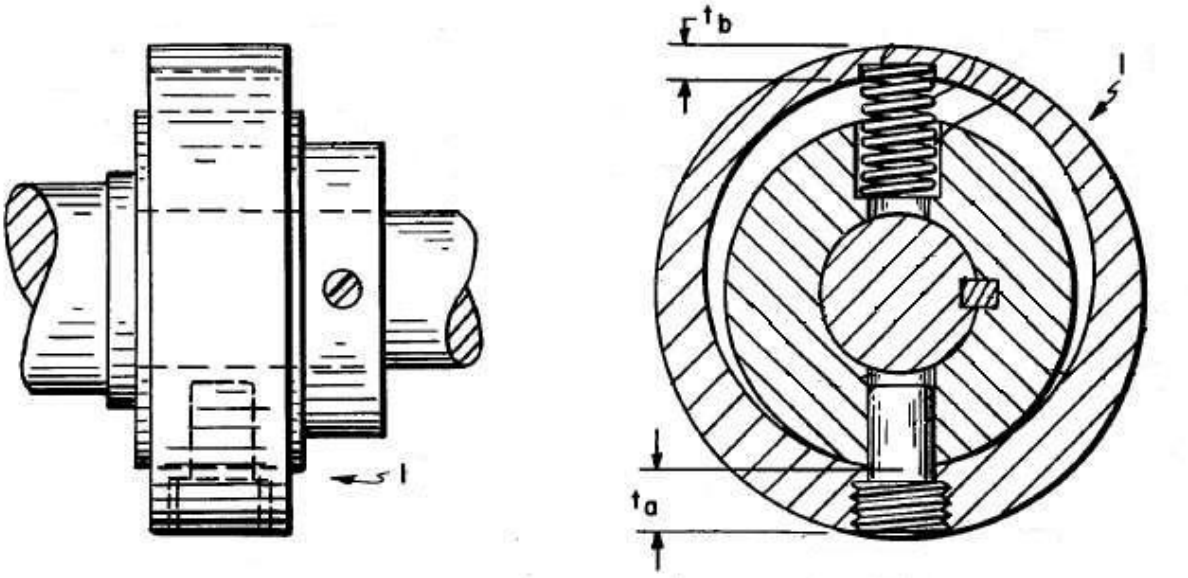



Figure 435. An eccentric weight will overcome the spring pressure on overspeed and hit the trigger of the emergency trip

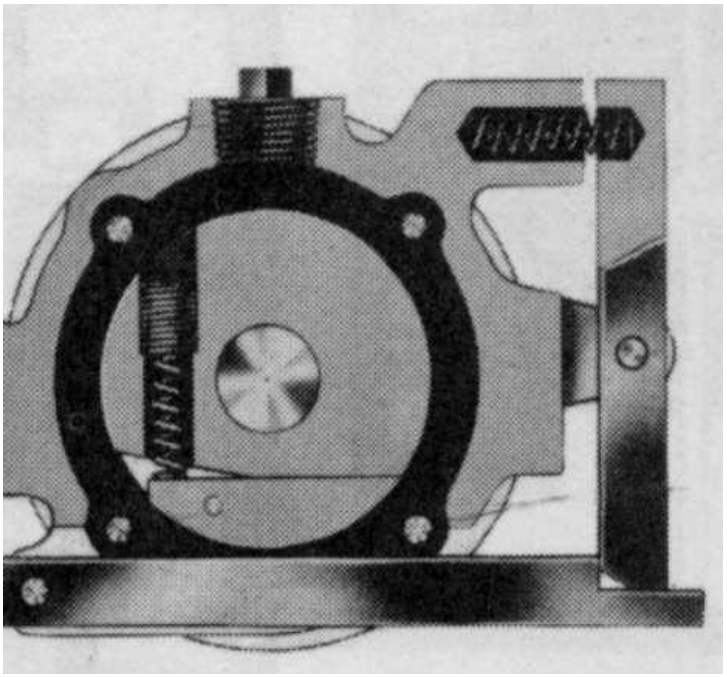


Figure 436. The half-moon weight at the bottom of the shaft will move out if overspeeding occurs, hitting the trip lever and shutting off steam to the turbine

## 44. List the various forms of protective governors commonly used on turbines and explain.

1. Overspeed Governor

2. Pre-emergency Governor

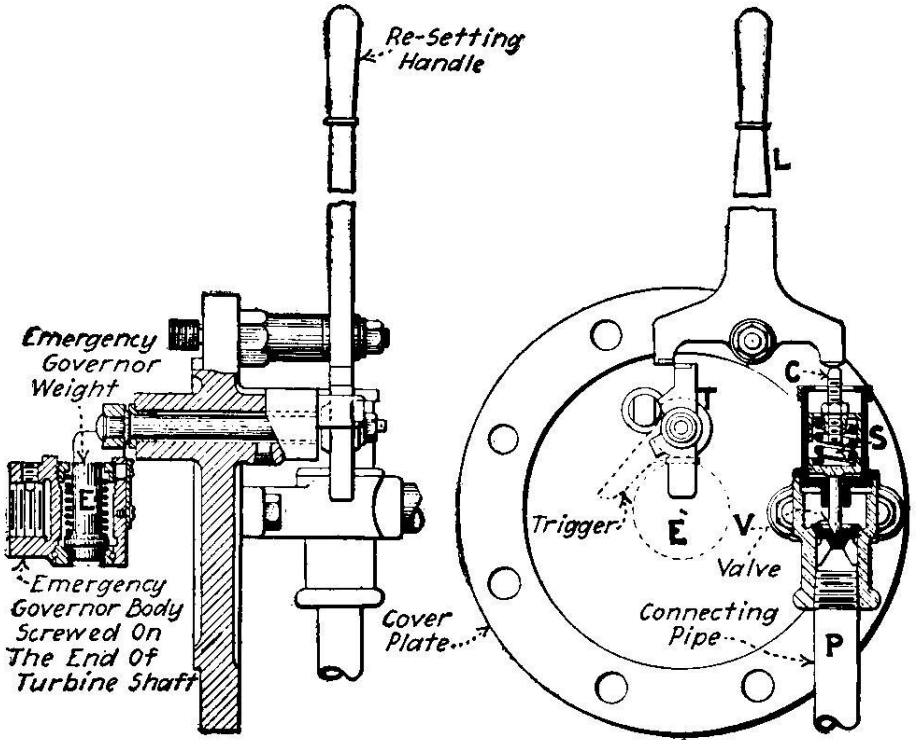



Figure 437. Automatic emergency governor or safety stop which is used on some Westinghouse turbines in connection with the throttle valve.

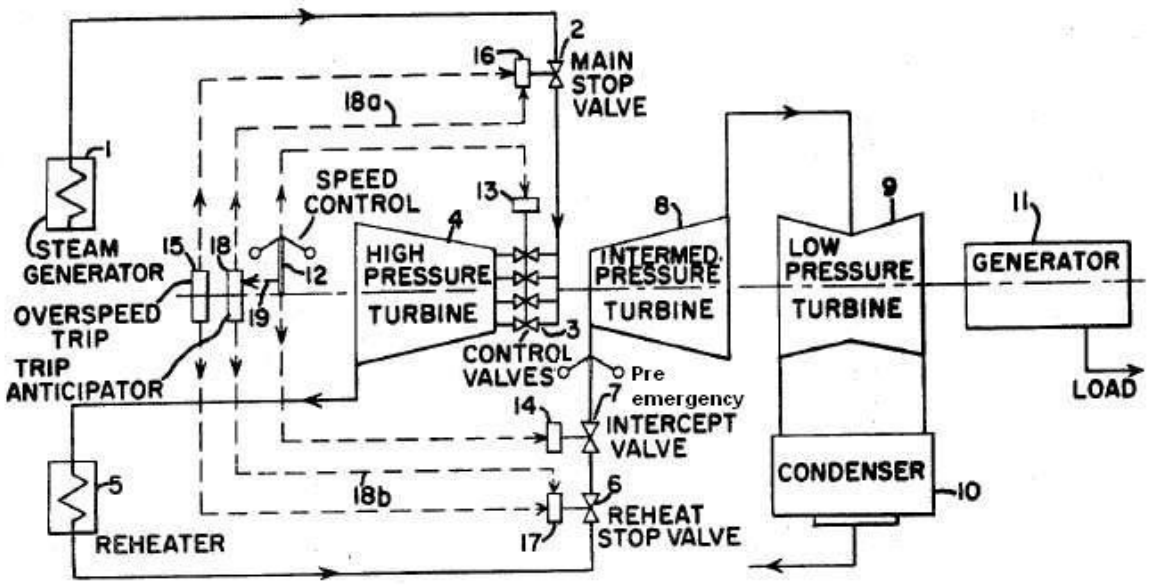



Figure 438. The pre-emergency governor controls the intercept valve 7 and starts to close at 1% overspeed and is fully closed at 5% overspeed

## 45. What type of governor is the overspeed trip?

The overspeed trip is a Safety Governor and not a speed or load controlling governor. Its purpose is to protect the turbine against overspeeding in case of failure of the operating governor. At 10% overspeed this safety governor automatically trips the stop valve, the governor valve, a separate overspeed valve, or combination of these. One type emergency governor uses a weighted pin set or recessed into the shaft. This pin is held in position by spring pressure. As the turbine begins to overspeed the spring pressure is overcome by centrifugal force working on the pin. As the pin slides out it is adjusted by spring pressure to trip a trigger that causes a valve to close shutting off steam flow to the turbine thus prevent damage due to overspeed.

*D.E.S.C. Turbine Operation page 4 , S&V page 248*

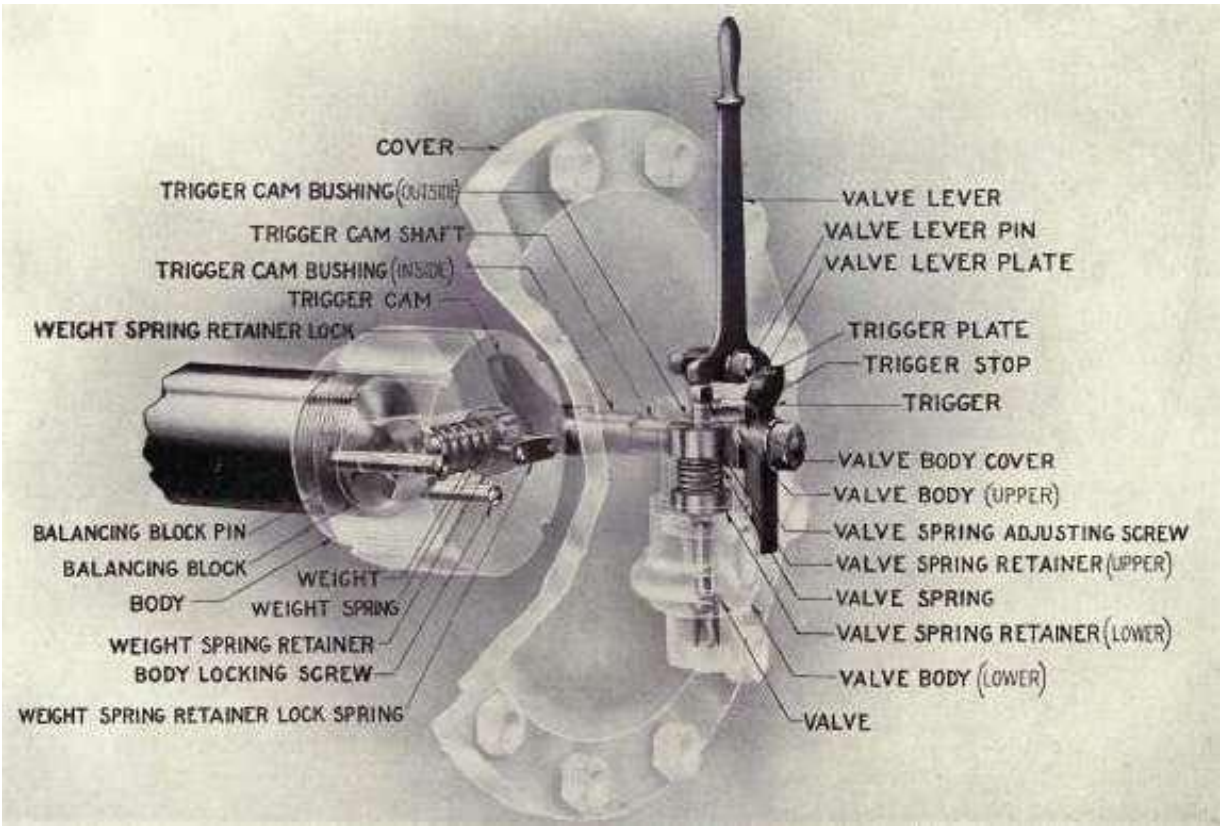



Figure 439. Overspeed trip in phantom view showing all the parts

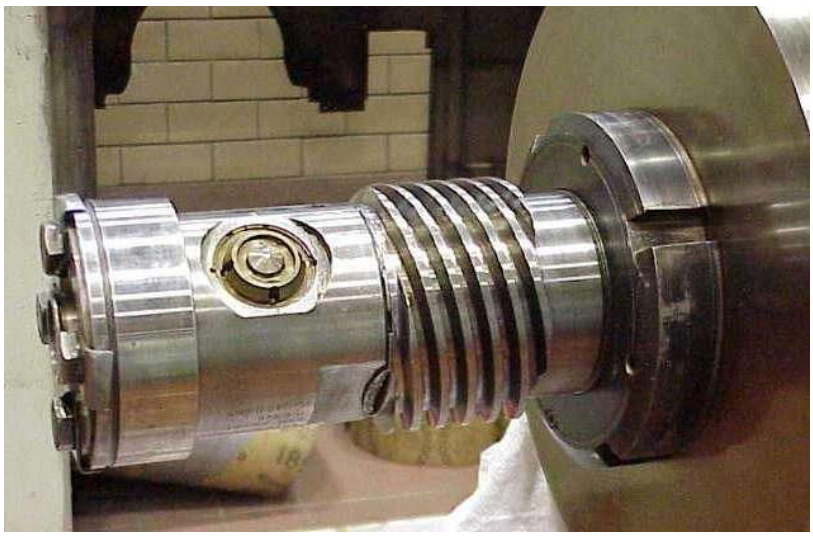


Figure 440. Showing the overspeed trip button and the worm gear that drives the governor

## 46. What percent of overspeed will trip off a turbine?

Overspeed governors are provided on all generating turbines and trip at 10% overspeed.

*Kents 11th Edition. pages 8-49*

## 47. At what speed will a 3600 rpm turbine trip out on overspeed?

If a turbine operates at 3600 rpm the overspeed trip will drop the turbine out at 3960 rpm. If the turbine operates at 1800 rpm the overspeed trip will drop the turbine out at 1980 rpm.

*Kent. 11th Edition, page 8-49*

## 48. What is the safe maximum tripping speed of a turbine operating at 2500 rpm?

The rule is to trip at 10 percent overspeed. Therefore, 2500 x 1.10 = 2750 rpm.

## 49. What maybe the possible causes for the safety trip to trip at normal speed?

Excessive vibration.

Leakage in the pilot valve.

Dirt deposits in the safety trip valve.

## 50. What maybe the possible causes for the safety trip tripping during load variation?

Light load and high inlet steam pressure.

Safety trip set too close to the operating speed of turbine.

## 51. How do dirt deposits cause safety to trip at normal speed?

Dirt may find its way to the safety trip valve and get deposited around the spring end cap. This will lessen the clearance between the safety trip valve and the spring end cap. As a result the steam pressure in the spring cap gets lowered allowing the valve to close. The spring end cap as well as safety trip valve should be cleaned at overhaul to prevent this.

# Machinist Struck and Killed by Fragments from Ruptured Steam Turbine Housing

On Saturday, February 24, 2001, a 51-year old journeyman machinist was killed when he was struck by fragments projected from a steam turbine that broke apart during an overspeed trip test.

Employees from three companies were onsite at the time of the fatality. The victim's company (Company A) had recently rebuilt the turbine and was assisting with bringing it online. A second company (Company B) operated the steam turbine. A third company (Company C) owned the turbine was responsible for start-up and testing, general maintenance, and repair of the turbine.

The No 3 turbine involved in the fatality was a General Electric steam turbine purchased in 1930. Of the four turbines owned and used by Company C to supply wind to its blast furnaces, Number 3 and 4 turbines were identical. The other two were from a different manufacturer. No 3 turbine had been out of service for maintenance since August, 2000, when a piece of steel in a steam line had caused bucket damage. The shaft, rotor, and turbine buckets had been sent to Company A to be rebuilt. Company A had been conducting maintenance on this turbine and the three other steam turbines in this facility for many years. The turbine had been reassembled at the owner's site in December, 2000, and was being brought online through January, 2001.

On the day the fatality occurred, overspeed trip tests were to be conducted by employees from the company that operated the equipment, Company B. Prior to the overspeed trip tests, workers from Companies A, B, and C were conducting a test which required running the turbine on idle for 45 to 60 minutes. There had been problems with a bearing blowing out. The victim was involved in the idling tests. The workers were on the platform near the turbine so they could place their hands on the housing to feel the bearing temperature through the housing during the idle tests. Those tests had been completed. The victim remained on the platform after the completion of the idle test to observe the overspeed trip test. He was not taking part in the overspeed trip test.

Plant Area Showing Former Site of Turbine No 3 and Site of Turbine No 4

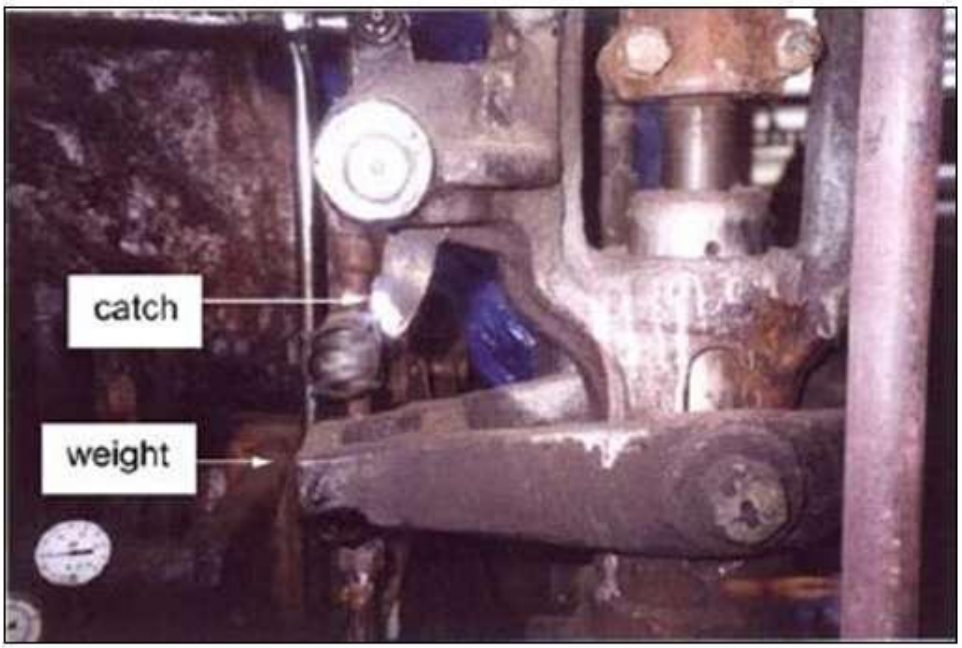
Figure 441. Site of the fatal accident. #3 turbine had been removed when this photo was taken

Three overspeed trip tests were required before returning the steam turbine into operation. The overspeed trip test consisted of allowing the turbine to accelerate to a maximum rpm speed to test a mechanical shutoff valve. The mechanical shutoff valve was designed to cut off the flow of steam to the turbine at the maximum rpm and thereby prevent the turbine from accelerating to a dangerous speed. Employees were not sure of the actual maximum operating speed or trip speed of the turbine. The General Electric Owner/Operator Manual stated that the operating speed was 3370 – 4100 rpm. Some employees thought it was 4100 to 4200 rpm. One employee indicated that the operating speed was about 4100 rpm. This same employee was not sure but thought that tests to trip the overspeed protection device were done at or as close to 4510 as possible. The manufacturer's brass tag on the turbine stated the mechanical shutoff valve would trip at 4500 rpm.

At the time of the incident the employees were unaware that the turbine overspeed trip tests could have been conducted from a Compressor Control Corporation (CCC) control unit computer if it had been programmed to do so. The CCC computer had not been programmed, so the test was conducted as it had been in the past. A worker on the platform next to the turbine attached a loop calibrator to the steam admission valve, a transducer actuated by an electrical current. The electrical current was read and adjusted on a milliamp meter. The transducer ultimately controlled the amount of steam provided to the turbine and thereby its speed.

The rpm gauge mounted on the turbine and located at a critical area adjacent to the emergency mechanical trip device was not accurate and did not function per design, so no one had been positioned there to physically trip the mechanical device in case it did not trip on its own. The only functioning rpm readout was on the CCC rpm readout panel on the wall approximately 35 feet from the turbine platform. A person stationed at the CCC rpm readout panel signaled to the person controlling the milliamp meter on the turbine platform whether the rpm should be increased or decreased. Hand signals were used because of the excessive background noise.

Results of the investigation indicated that the hand signals used by the various workers who conducted the overspeed trip tests were not consistent. Some workers used one hand to indicate rpm by raising fingers to indicate 1000's and 100's. Others signaled by using their hands. The higher hand indicated 1000's and the lower hand indicated 100's.

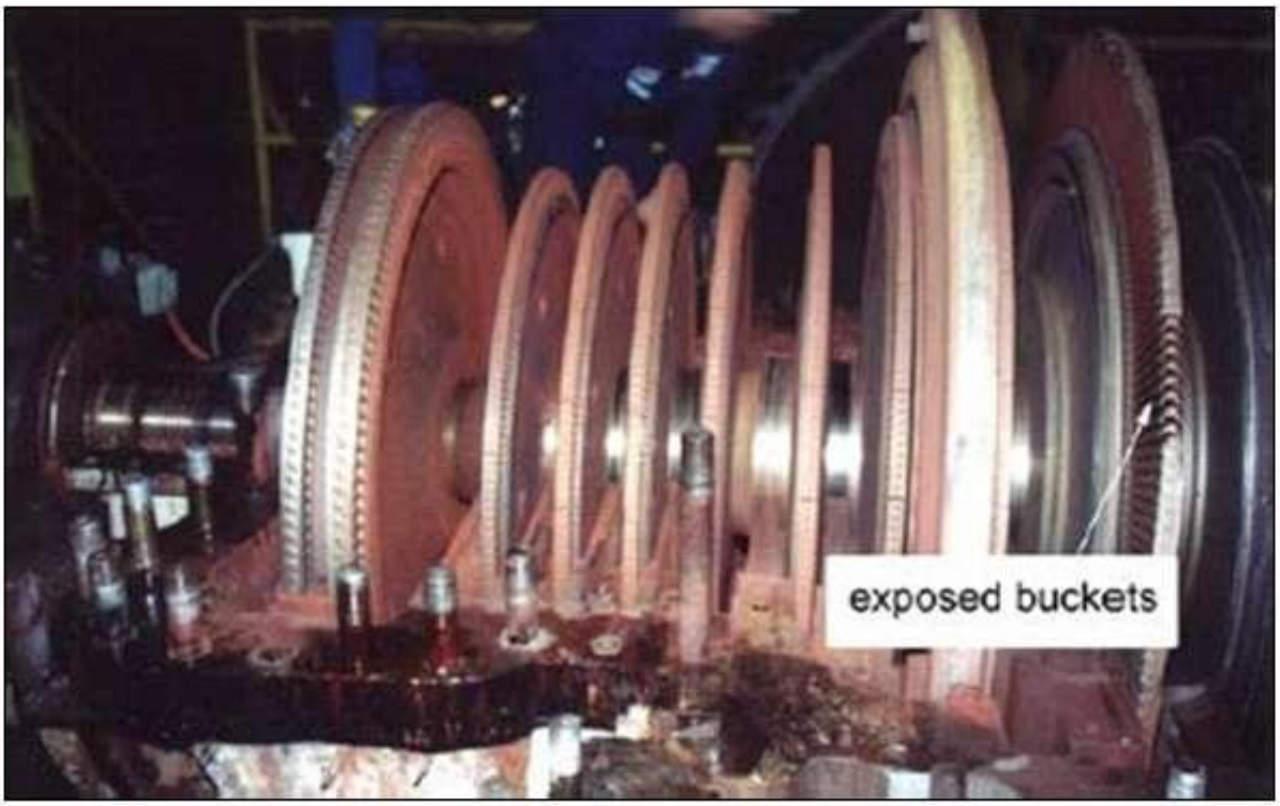



**Mechanical Trip Device**

Figure 442.

At approximately 1:00 p.m., the turbine was started and idled at about 1000 rpm for about 45 minutes to warm up. At approximately 1:55 p.m., the first of the three required trip tests was conducted. According to one employee the mechanical shutoff valve tripped out at 4523 rpm.

On the second of the three planned trip tests, the mechanical shutoff valve did not trip properly. The operator monitoring the rpm at the CCC rpm readout panel was for some reason momentarily unaware that the turbine was exceeding its limit. By the time he recognized the situation and signaled for the milliamp current that was controlling the transducer to be reduced, it was too late to stop the turbine from overspeeding. The mechanical shutoff device did not trip. The turbine buckets overran their safe speed causing a catastrophic failure of the turbine rotor. There were 12 rings on the turbine shaft. One hundred buckets broke away from one of the twelve rings on the shaft and pierced the two-inch thick turbine housing. The other eleven rings remained intact. The fragments resulting from the broken housing and turbine buckets struck the victim causing severe injuries and death.




**Turbine Shaft and Rings**

Figure 443.

**Several factors contributed to the death of the worker:**

- No process existed to safely conduct the overspeed trip test in accordance with the General Electric Owner/Operator Manual, industry guidelines, and consensus standards for steam turbines such as American National Standards Institute (ANSI), American Society of Manufacturing Engineers (ASME), American Society for Testing and Materials (ASTM) and Factory Mutual.
- No one had been trained to conduct the test in a safe manner.
- No clear delegation of responsibility or accountability existed.
- The safety tests were conducted on a mechanical safety device with no redundant safety controls in the case of the failure of the mechanical safety device.
- The rpm gauge on the turbine was not functional.
- The rpm readout was located some distance from the person controlling the steam release resulting in the necessity of using hand signals to communicate regarding supplying more or less current.
- The hand signals used by the persons conducting the test were not consistent.
- Workers not authorized to be present during the test were present in positions that placed them at risk of injury and death.
- The turbine blower was disconnected from the system so the turbine had no opposing force to overcome and came up to its overspeed condition quickly.
-

**Changes have been made since the fatality occurred including:**

- The No 3 steam turbine involved in the fatality has been removed from the plant. Changes were implemented for No 4 turbine. It is identical to No 3.
- Procedures for conducting the overspeed trip test according to manufacturer's instructions, industry guidelines, and consensus standards were developed.
- The CCC computer control was programmed so that the test can be conducted from inside a control booth.
- The position of the control booth was changed and the structure of the control booth was improved to allow workers to operate the steam turbine tests from inside the control booth.
- Workers were trained regarding the procedures to be followed to conduct the overspeed trip test and their individual responsibilities associated with it.
- Redundant safety controls were established for conducting the overspeed trip test: the manual shutoff valve is the primary control, the person in the control booth conducting the test is located next to an emergency stop; the computer controlling the test is programmed to electronically shut down at a particular ceiling speed.
- No one is allowed near the equipment during the test.
- Barricades, warning signs, and markings identify the restricted area. These warnings can be seen in as they were implemented for the No 4 steam turbine.
- Procedures for conducting the test were developed and all workers were trained in using those procedures.

# Chapter 11 Lubrication

## 1. Explain lubrication system on a large condensing turbine.

Oil is used to lubricate the bearings on either end of the turbine shaft and the thrust bearing, and act as a hydraulic fluid to operate the governor.

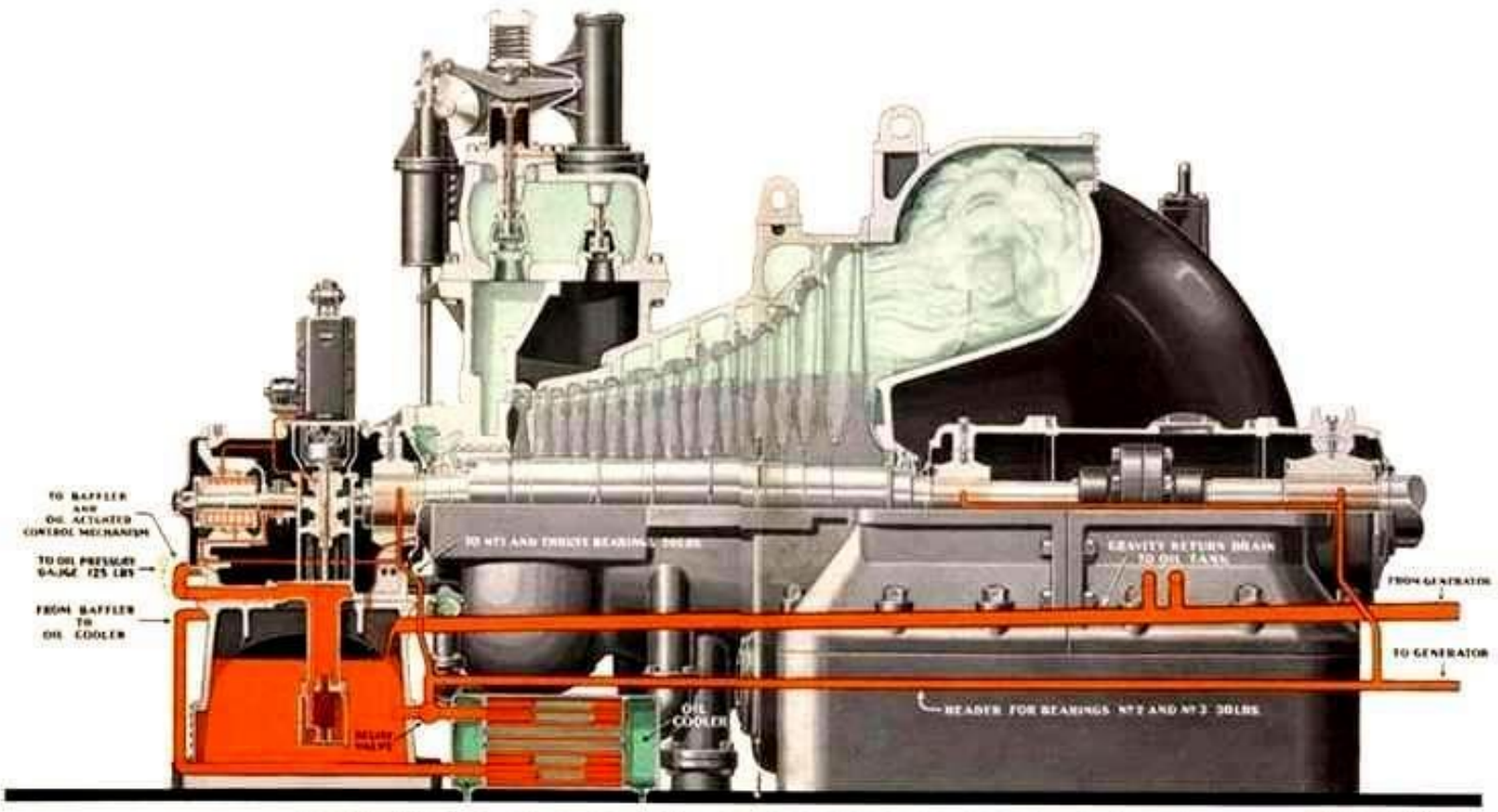
The lube system consists of an oil reservoir, main oil pump (shaft driven), strainers, relief valves, oil coolers, and oil piping.

The main oil pump is usually shaft driven and the auxiliary is steam or electric driven. A pressure switch will start and stop the auxiliary oil pump automatically, according to the pressure from the main oil pump. The auxiliary oil pump is used for start up and shut down.

In normal operation oil is delivered from the main oil pump at 40 to 125 PSI and some oil flows to the governor control mechanism. The rest is delivered through the strainer and cooler to the bearings at 5 to 15 PSI controlled by the pressure relief valve which relieves back to the reservoir.

Oil temperature to the bearings is 110° F. to 120° F.

Oil temperature leaving the bearings is 140° F. to 150° F.


TO BAFFLER AND OIL ACTUATED CONTROL MECHANISM
FROM BAFFLER TO OIL COOLER
GRAVITY RETURN DRAIN TO OIL TANK
FROM GENERATOR
TO GENERATOR
OIL COOLER
HEADER FOR BEARINGS Nº 2 AND Nº 3 30 LBS

Typical direct drive turbine, showing principal features of pressure circulating oil system. Twin pumps supply oil at 125 lbs. pressure to oil hydraulic control mechanism; oil pressure to bearings is reduced to 10 lbs. by suitable baffler and relief valve.

Figure 444. Steam Turbine Lube Oil System

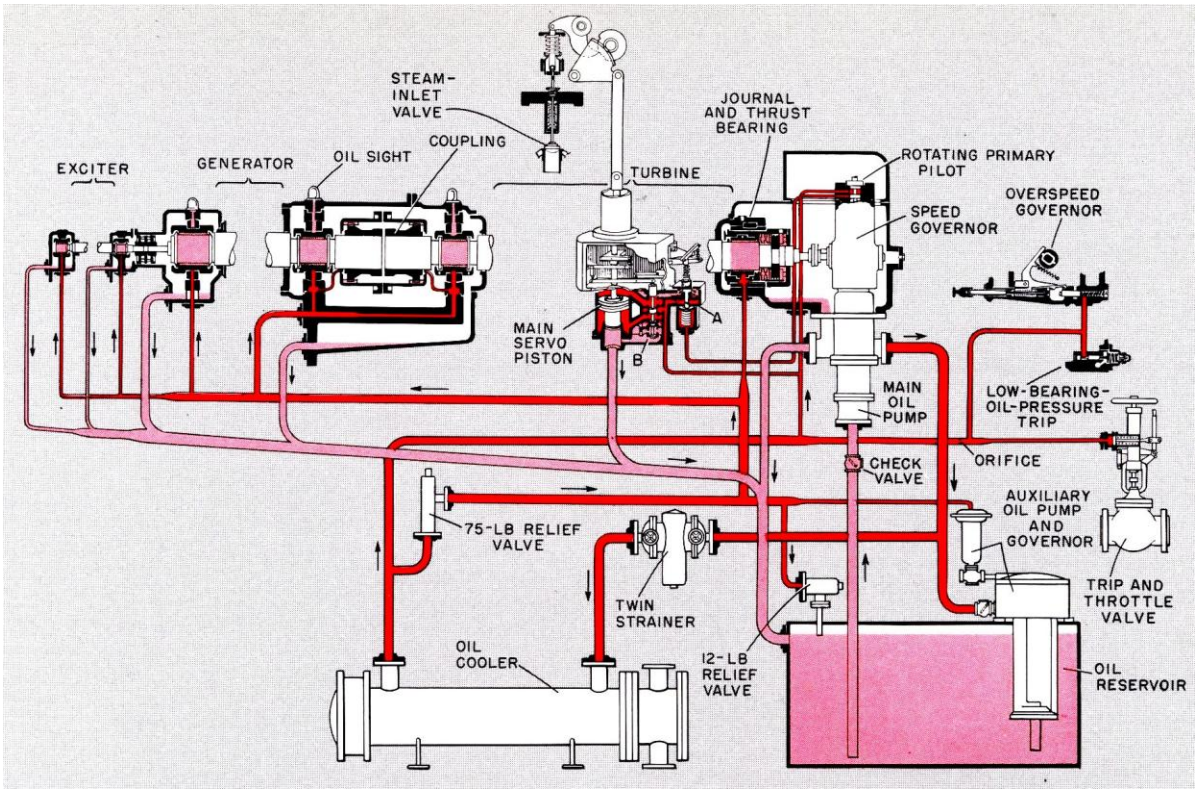



Figure 445. Steam turbine lube oil system diagram

Figure 446. Medium sized steam turbine lubricating oil system

## 2. What qualities make up a good turbine oil?

1. Turbine oil is a mineral oil not compounded with animal or vegetable oils. It may have additives to prevent rust.

2. Recommended viscosity 140 to 250 S.S.U. at 100° F. depending on turbine type.

3. Oil should separate from water. This is called having low emulsification.

4. Flash point should not be below 325° F.

5. Should not form deposits.

## 3. What are the properties of a turbine lubricating oil?

Lubricating oils are necessary for so wide a variety of uses that a large number of tests and specifications have been set up and standardized to give their various properties. Some tests, or analyses, deal mainly with new oils, others with used oils, and many, with both new and used oils. In relation to turbine oils, the following terms are commonly used.

1. Viscosity - resistance of an oil to flow

2. Viscosity index - flow characteristics versus temperature

3. Neutralization or electrometric acid number - how acidic the oil is

4. Steam emulsion number - ability of oil and water to separate

5. Demulsibility - rate per hour that water settles out of oil

6. Precipitation number - amount of sludge in the oil

7. SAE number - viscosity number found with a Saybolt Seconds Universal meter

8. Flash point - temperature the oil gives off a momentary flash in presence of fire

9. Fire point - the temperature the oil actually catches fire

10. Carbon Residue - how much carbon is left after distillation

11. Pour Point - lowest temperature at which an oil will flow

12. Gravity API - density of oil. The heavier the oil, the lower the API

13 Saponification Number - grams of potassium hydroxide to saponify the oil

14. Oxidation Tests - oil, air, and a catalyst used to determine rusting

15. Corrosion Tests - Navy sea water rusting test

16. Color - matching oil sample to color standards

17. Oiliness - the difference between in fluid friction not accountable to viscosity

The manufacturer will specify an oil with the qualities required for the specific design of turbine you have purchased.

*S&V page 82-83, Kents 11th page 8-46, Croft Turbine page 230*

## 4. What type of oil is used in steam turbines?

Lubricating oils for turbines are mineral oils not compounded with animal or vegetable oils. They can be manufactured from crude petroleum from various fields. The Pennsylvania fields produce a paraffin-base crude oil; the western fields, an asphalt-base crude; and the mid-continent fields, a mixed base crude. Turbine oils commonly have inhibitors or additives mixed with them. These additives aside from reducing the tendency to oxidize, may retard rusting in the lube-oil system, improve the oil viscosity index, improve the oiliness of lube oil, and bring about other beneficial results.

*S&V page 48*

## 5. What happens if oil emulsion is formed in the bearing oil?

Emulsification is oil and water mixing. Emulsion speeds up oxidation and sludge formation.

This causes lower lubricating value of the oil and may cause deposits to settle out on the bearings, thus overheating and reducing the life of the bearing.

*S&V page 81 – 85*

Shell Turbo Oil GT:
The right oil makes all the difference. Gear box thrust bearing.
After 16,500 running hours
on a mineral turbine oil
After 30,000 running hours
on Shell Turbo Oil GT 32

Figure 447.

## 6. How is water removed from the turbine oil system?

The two (2) main methods are:

1. Settling Tank - Oil from the turbine while still warm is pumped to the settling tank where it is allowed to set for 10 days. Water and impurities settle to the bottom. Clean oil is drawn off the top.

2. Centrifugal Separator

In some instances the entire batch of oil is removed and reconditioned. In others a portion is continually circulated through a reconditioning apparatus.

3. Package Oil Reclamation Units use heat and vacuum conditions to drive off moisture and discharge it through a vacuum pump.

*W. & L. page 554, D.E.S.C. Lubrication Section page 20, S&V page 87, W. & L. page 552*

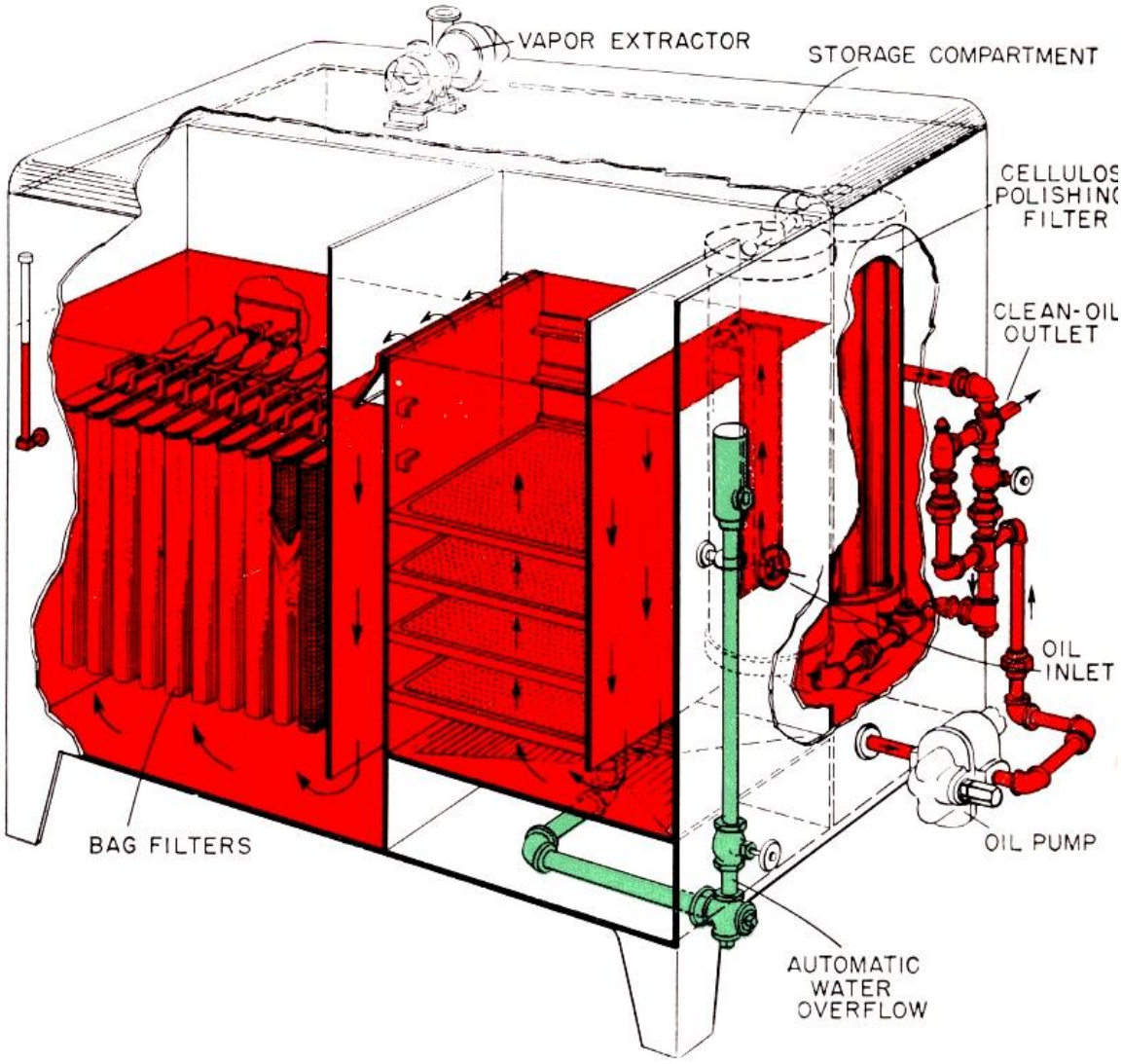



Figure 448. Batch oil settling tank

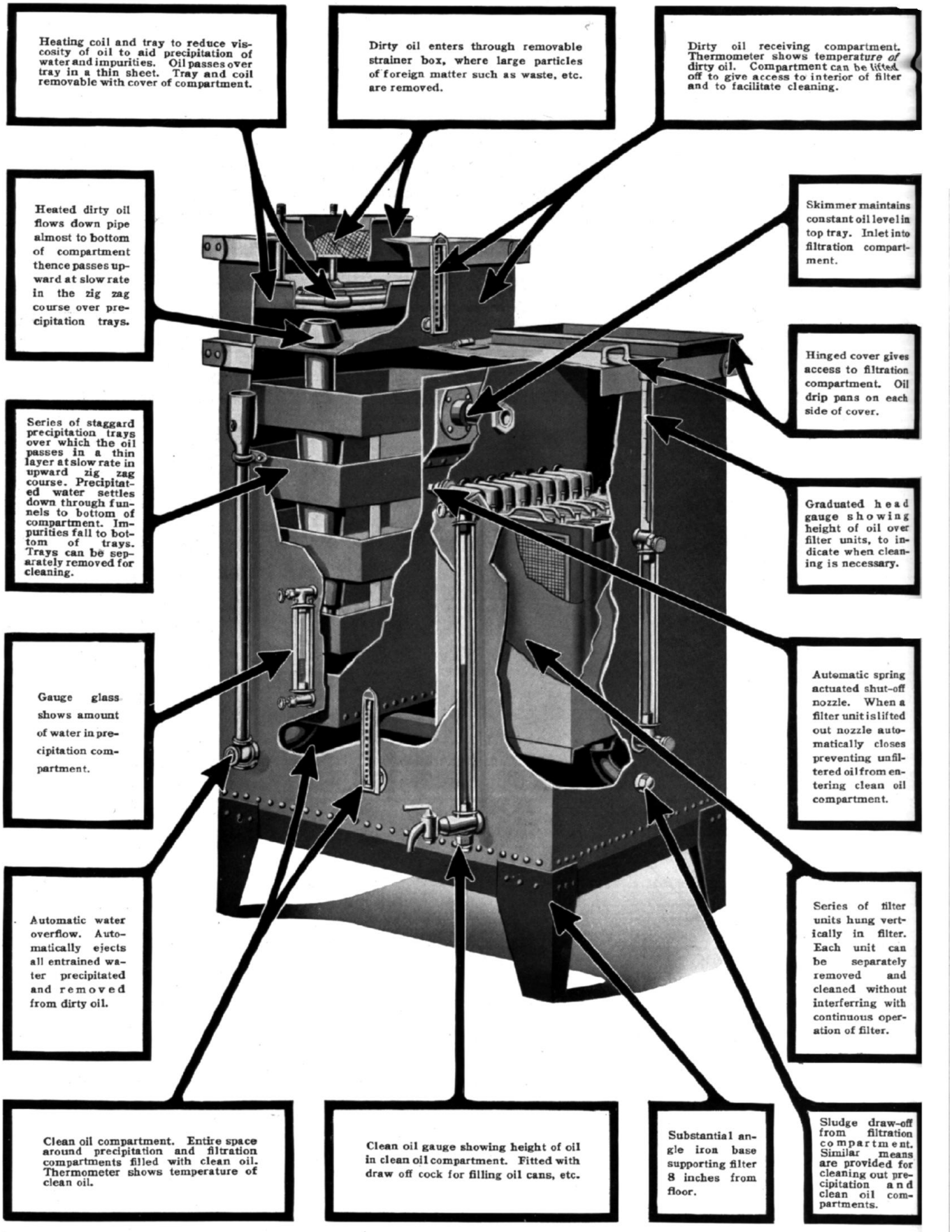

Heating coil and tray to reduce viscosity of oil to aid precipitation of water and impurities. Oil passes over tray in a thin sheet. Tray and coil removable with cover of compartment.
Dirty oil enters through removable strainer box, where large particles of foreign matter such as waste, etc. are removed.
Dirty oil receiving compartment. Thermometer shows temperature of dirty oil. Compartment can be lifted off to give access to interior of filter and to facilitate cleaning.
Heated dirty oil flows down pipe almost to bottom of compartment thence passes upward at slow rate in the zig zag course over precipitation trays.
Skimmer maintains constant oil level in top tray. Inlet into filtration compartment.
Hinged cover gives access to filtration compartment. Oil drip pans on each side of cover.
Series of staggard precipitation trays over which the oil passes in a thin layer at slow rate in upward zig zag course. Precipitated water settles down through funnels to bottom of compartment. Impurities fall to bottom of trays. Trays can be separately removed for cleaning.
Graduated head gauge showing height of oil over filter units, to indicate when cleaning is necessary.
Gauge glass shows amount of water in precipitation compartment.
Automatic spring actuated shut-off nozzle. When a filter unit is lifted out nozzle automatically closes preventing unfiltered oil from entering clean oil compartment.
Automatic water overflow. Automatically ejects all entrained water precipitated and removed from dirty oil.
Series of filter units hung vertically in filter. Each unit can be separately removed and cleaned without interferring with continuous operation of filter.
Clean oil compartment. Entire space around precipitation and filtration compartments filled with clean oil. Thermometer shows temperature of clean oil.
Clean oil gauge showing height of oil in clean oil compartment. Fitted with draw off cock for filling oil cans, etc.
Substantial angle iron base supporting filter 8 inches from floor.
Sludge draw-off from filtration compartment. Similar means are provided for cleaning out precipitation and clean oil compartments.
The most practical and efficient Oil Filter on the market. This is the filter used on all systems for turbines.
For turbines of 15,000 kw. and up use the No. 16 size.

Figure 449. Batch oil settling tank

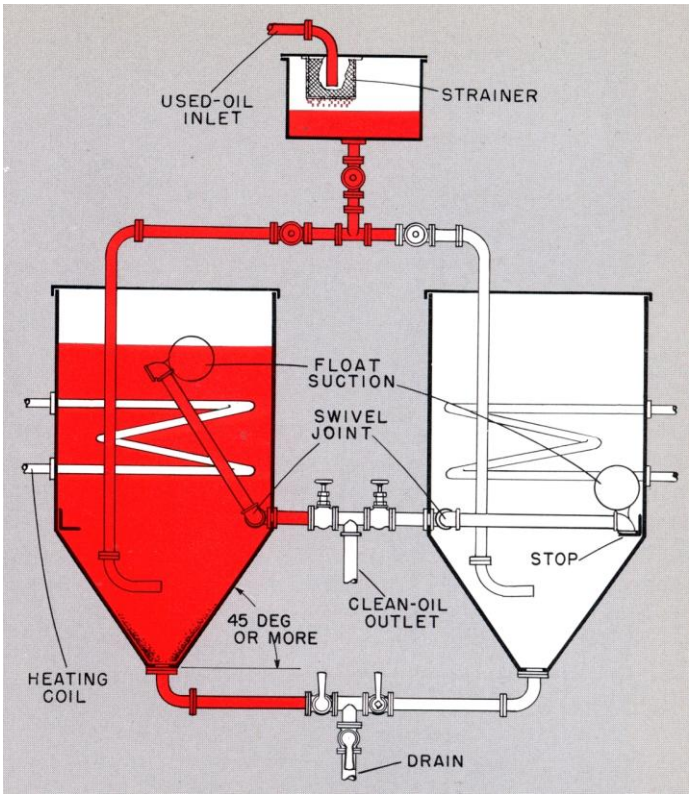
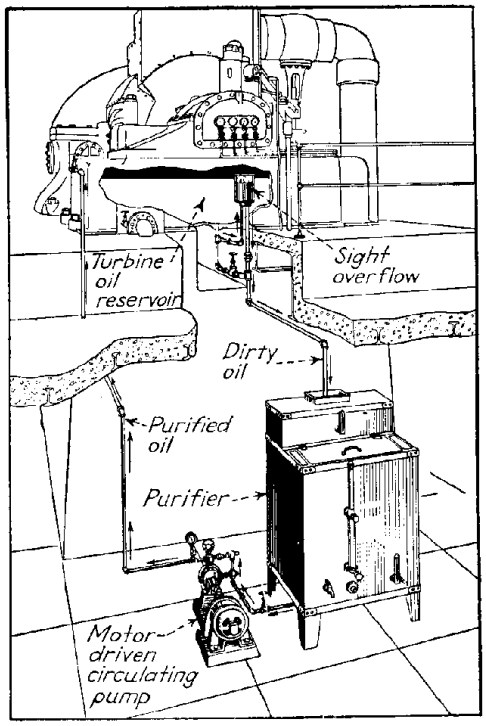



Figure 450. Batch Oil Cleaning

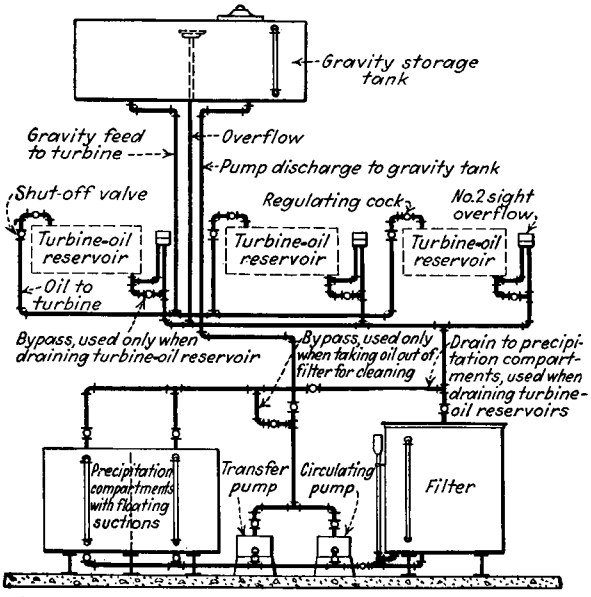
The entire batch of oil is drained from the turbine at stated intervals, preferably every two weeks, and a new batch at once pumped back to the turbine. The filter should have a precipitation compartment large enough to hold the entire batch of the largest turbine. The clean-oil compartment of the filter generally holds more than one batch and may also be used for the storage of new oil. When the batch has been let down into the filter from the turbine it is heated, allowed to stand at perfect rest for a period of time to precipitate its impurities, and then run through the straining medium to the clean-oil compartment.

One batch filter will serve a number of turbines and the oil will be made cleaner at less expense of operation than if partial filtration with circulating systems were used.




Continuous by-pass purification system applied to a steam turbine.

Figure 451.




Combination batch and by-pass purifying system arranged so that one filter and one pair of settling tanks serve three turbines.

Figure 452.

## 7. What is a centrifuge used for?

This device is a means for cleaning oil. It is used to remove water, solid matter, and some of the water-soluble oxidation products.

*S&V page 89*

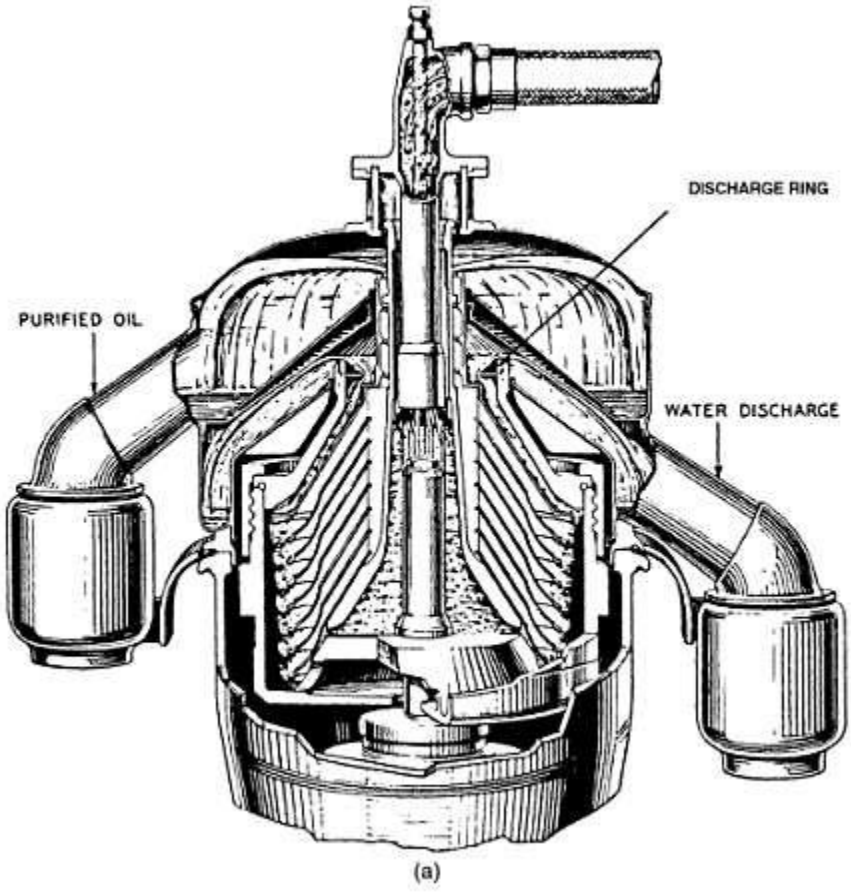



Figure 453. Oil centrifuge

Instead of filters many systems separate the oil from water and sludge by means of centrifugal units. As the impurities in the oil are generally heavier than the oil itself, they are thrown to the outside of the centrifuge and can be drawn off. These centrifuges are so designed that there is no loss of oil and even if the amount of water and sludge is very small, the oil cannot get into the drain line provided for the impurities.

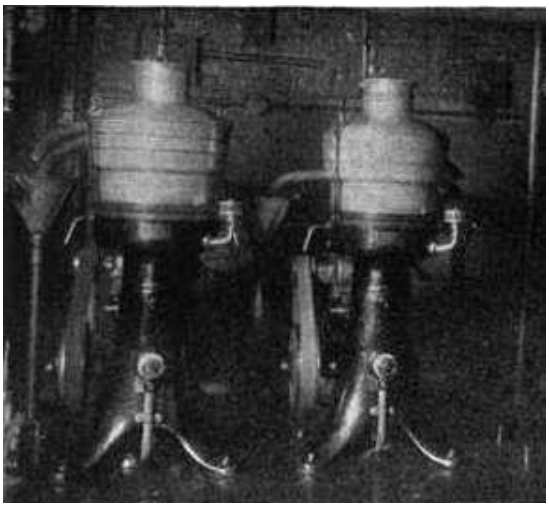


Figure 454. oil centrifuges

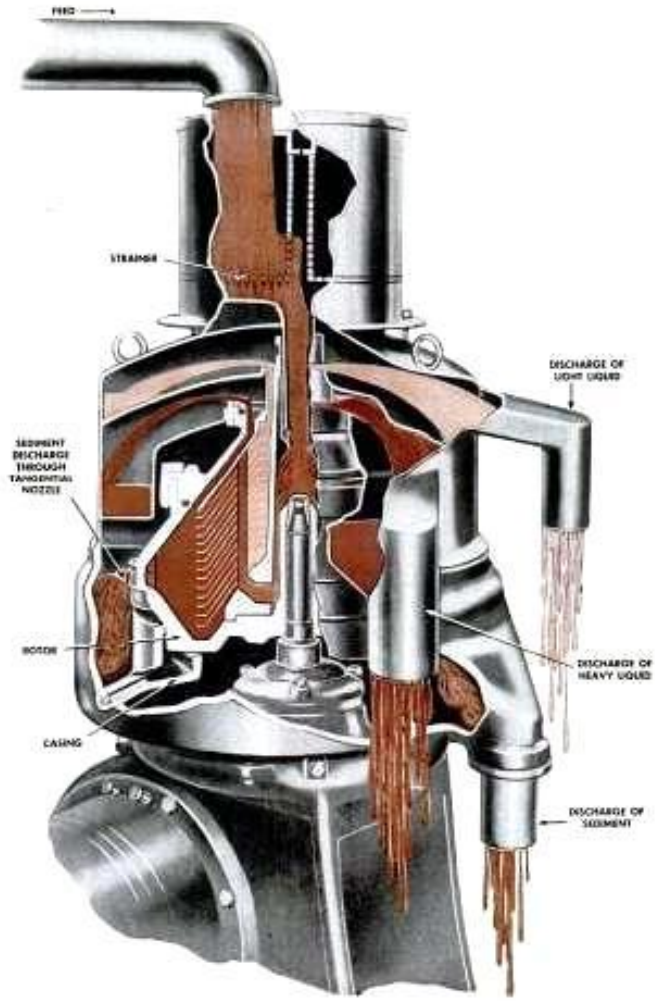
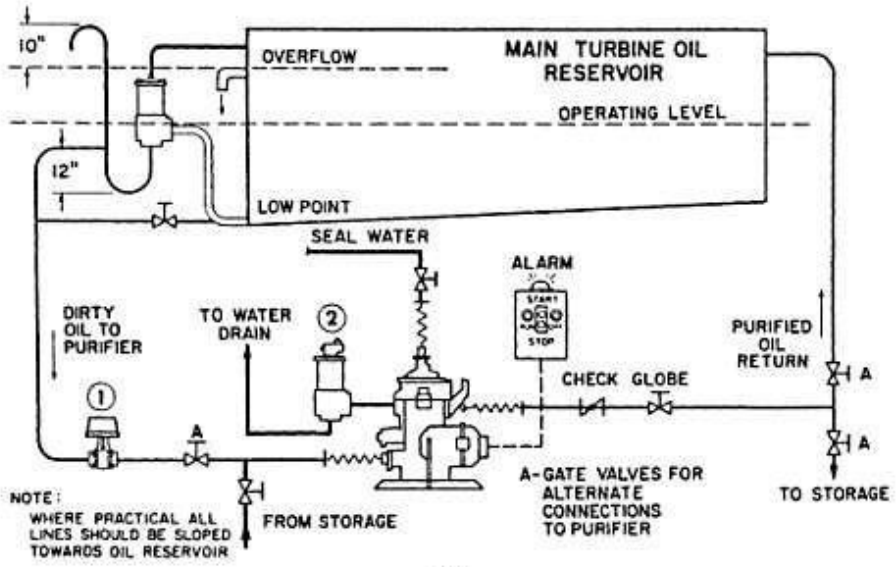



Figure 455. Centrifuge in operation

"There's no water or sludge in the oil coming from those DeLaval Centrifuges" said one of the engineers at the station in which the above photo was taken. These machines, operating on the continuous by-pass system, instantaneously centrifuge out of turbine oil the water and sludge which otherwise form emulsions and prevent proper lubrication. They keep the oil clean so that its lubricating quality is indefinitely maintained.

DeLaval Centrifuges save oil, but of far greater importance is the fact that they enable the oil to give bearings the fullest measure of protection. That is the real test of oil purifying equipment—not how much oil it saves, but how much insurance against turbine trouble it provides.

Leaky turbines have been kept in service for as long as 16 months with a DeLaval Purifier to remove water as fast as it leaked into the lubricating system. Oil so badly emulsified with dirt and water that it had the appearance of mud has been restored to practically its original state of purity with the same machine. Probably these conditions will never exist in your plant. But consider the fact that a machine capable of doing these things must have a marked advantage in purifying oil which is in average condition. Keep in mind also the insurance which is placed on turbines when such a machine is installed. *From a DeLaval advertisement*




Typical centrifugal separator cross section (top) and installation schematic (bottom). *(DeLaval Separator Company, Poughkeepsie, NY)*

Figure 456.

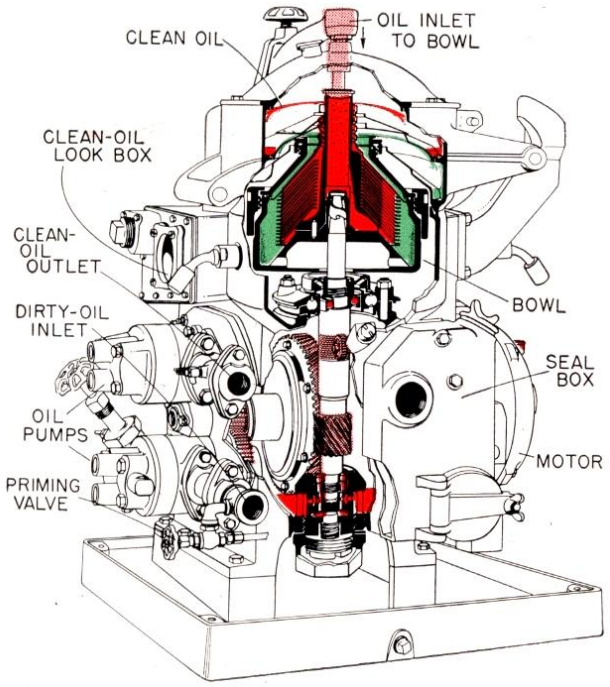



Figure 457. DeLaval Centrifuge

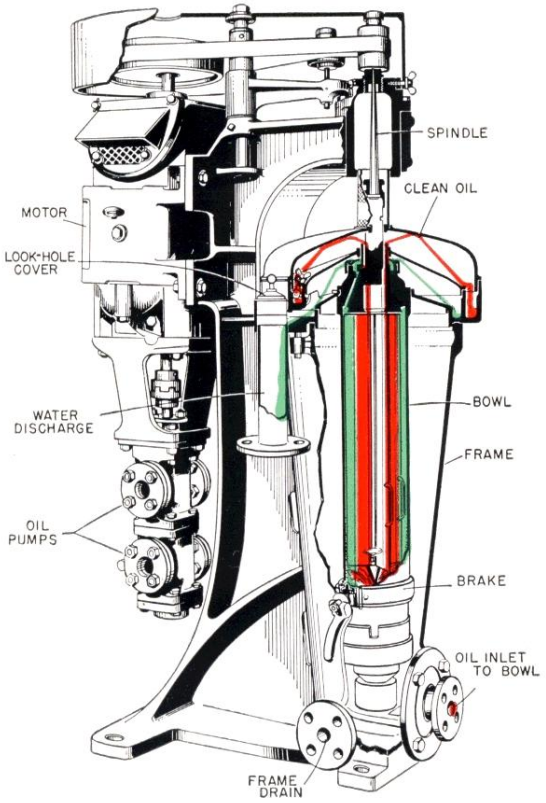



Figure 458. Sharples Centrifuge

## 8. Explain the operation of a centrifuge.

Dirty oil is fed to a rapidly rotating bowl. Centrifugal force tends to throw solid matter and water, which are both heavier than oil, to the walls of the bowl. The solid matter must be removed at intervals by stopping the centrifuge and cleaning the bowl. The dirty oil flows in steadily, since the water that separates from the oil and the resulting clean oil can be made to flow continually out of the bowl over rims.

*S&V page 89*

Figure 459. Centrifuge as part of a turbine lubricating system

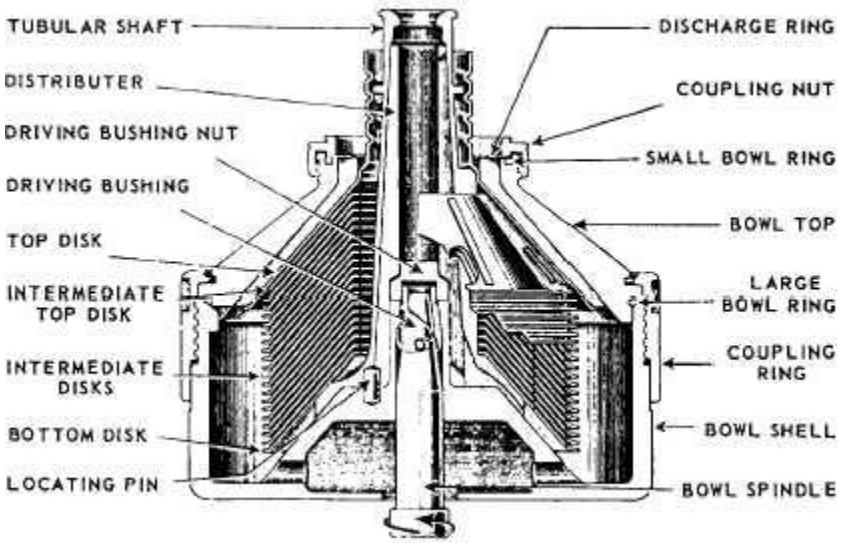



Figure 460. Internal parts of a centrifuge

## 9. Is the oil pressure higher or lower than water pressure on a turbine oil cooler?

The water pressure should be less than the oil pressure so that, in case of a leak, no water will enter the oil.

*S&V page 108*

## 10. Does oil or water run through the tubes on a turbine oil cooler?

The Allis-Chalmers Manufacturing Co. makes oil coolers of the shell and tube type construction in which the shell contains the oil and the tubes contain the water.

The reason given by Robert Hutchison, a design engineer with Allis-Chalmers, for this design is it provides a large volume of lubricating oil to be ready at all times, as opposed to the oil traveling through the tubes which may possibly become plugged and starve the oil pump. Another reason the oil is in the shell and not the tubes is that this design allows any particulates to settle to the bottom of the cooler for removal. This also allows easier cleaning of the water tubes.

*S&V page 109.The Allis-Chalmers Manufacturing Co.*

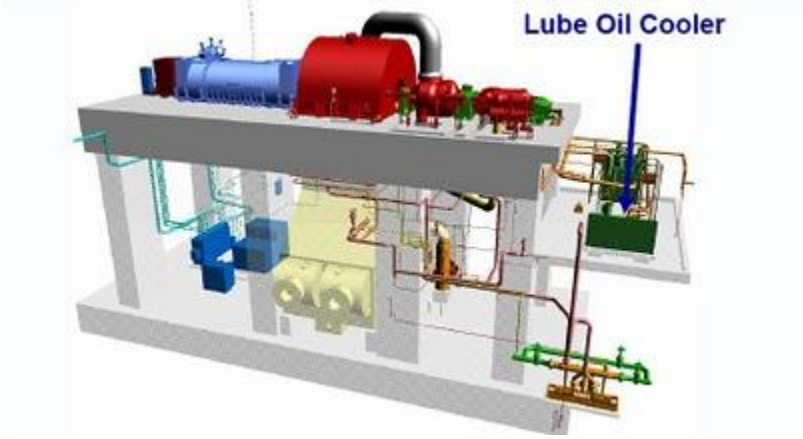



Figure 461. Lube oil cooler location in a turbine system

## 11. What should the temperature of the oil be entering and leaving the turbine bearings?

A turbine bearing will become hot due to friction. In addition, heat from high temperature parts of the rotor flows through the shaft and increases the bearing temperature. Cool oil must be supplied in considerably higher quantities than required for lubrication in order to provide needed cooling to the bearings. Large turbines will have an oil temperature of 120 to 130° supplied to the bearings. At the bearings 20° to 30° of heat will be picked up. The oil is then returned to the sump. Oil coolers are used to maintain proper temperature of oil to the bearings. The oil cooler is usually supplied with cooling water (condensate) from the hot well.

*S&V page 79 - 80*

*D.E.S.C. Lubrication page 31*

## 12. Why is it poor practice to allow turbine oil to become too cool?

If the turbine oil is allowed to become too cool, condensation of atmospheric moisture takes place in the oil and starts rust on the polished surfaces of the journals and bearings. Condensed moisture may also interfere with lubrication.

## 13. The capacity of the oil reservoir at the turbine for units over 5000 KW shall be sized so that the time required to circulate a quantity of oil equal to the capacity of the reservoir shall be how many minutes?

Oil reservoirs vary in size with different turbines and with the several manufacturers. A requirement for units of 5000 KW and over is that the capacity of the oil reservoir at the turbine shall be such that it will take not less than 10 minutes to circulate a quantity of oil equal to the tank capacity. With smaller turbines the period for complete circulation shall not be less than 5 minutes.

*Kents 11th Edition. page 8 44*.

## 14. With a "full fluid film", how does oil behave?

With a "full fluid film", oil shears like a deck of cards.

*Lubricants a Power special report August 1962 p. S.4*

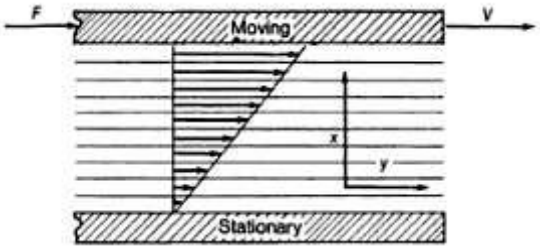



Figure 462. Oil shears like a deck of cards between two sliding surfaces

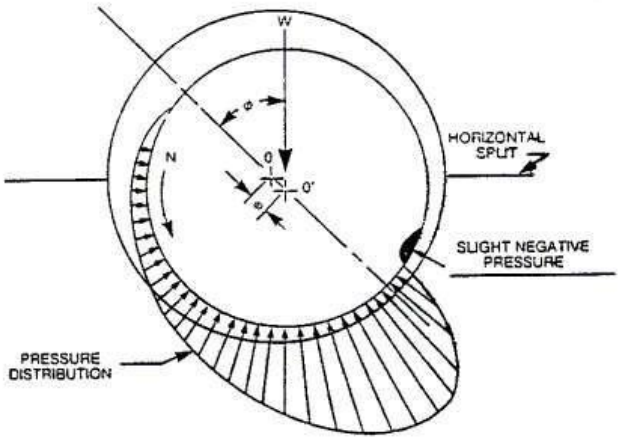



Figure 463. Shearing action of the oil on a shaft rotating inside the bearing

## 15. How is oil pressure maintained when starting or stopping a medium-sized turbine?

An auxiliary pump is provided to maintain oil pressure. Some auxiliary pumps are turned by a hand crank; others are motor-driven. This pump is used when the integral pump is running too slowly to provide pressure, as when starting or securing a medium-sized turbine.

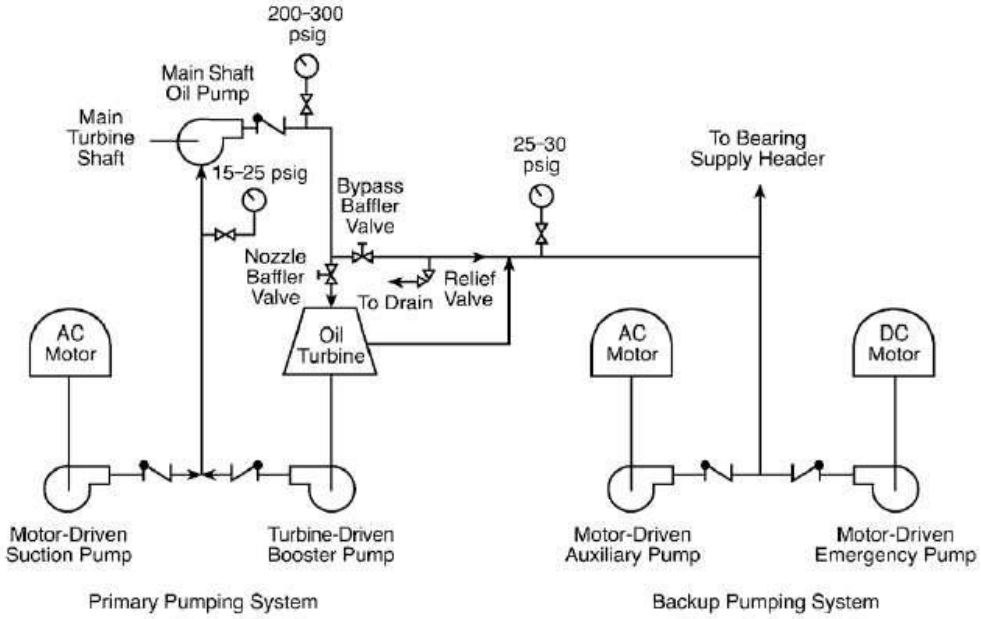



Figure 464. Oil pump system for a steam turbine

## 16. When the main oil pump is connected to the turbine shaft, how is the turbine kept oiled during start-up and shut down?

During starting and stopping operation of the turbine, when the rotor and main oil pump are not up to rated speed, a separately driven pump is needed to supply the oil. This auxiliary pump may be driven by either a small auxiliary turbine or an electric motor. During starting procedure, the pump automatically cuts out of operation when the main oil pump develops rated pressure and speed; during shut down the auxiliary oil pump automatically cuts in when the main oil pump speed and pressure drop below rated values thus insuring a steady oil supply while rotor is still turning.

*D.E.S.C. Lubrication page 31*

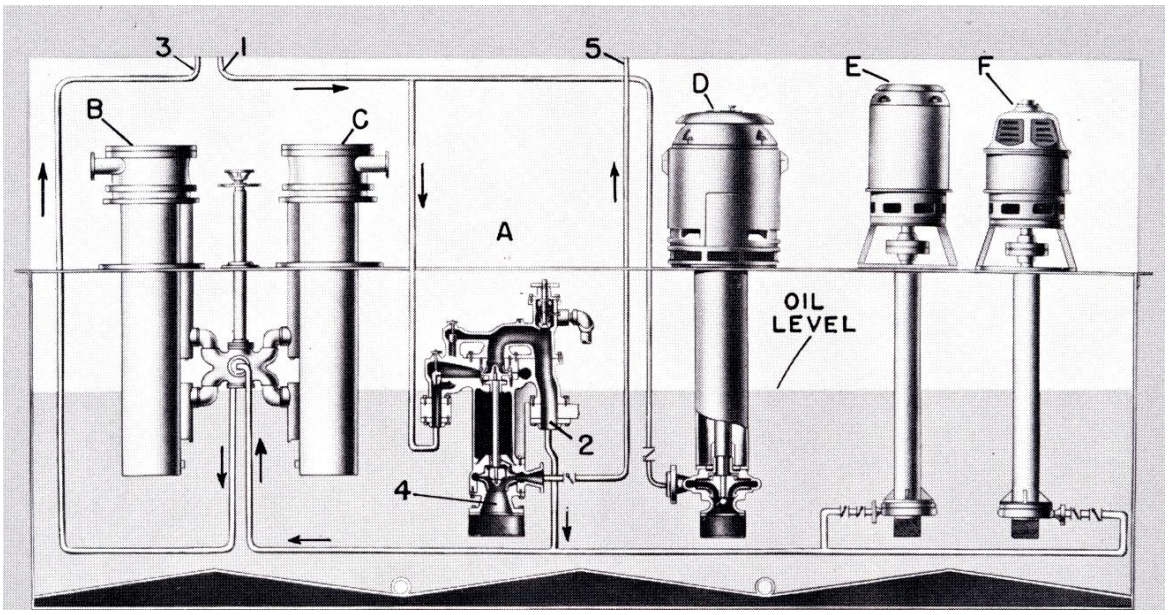
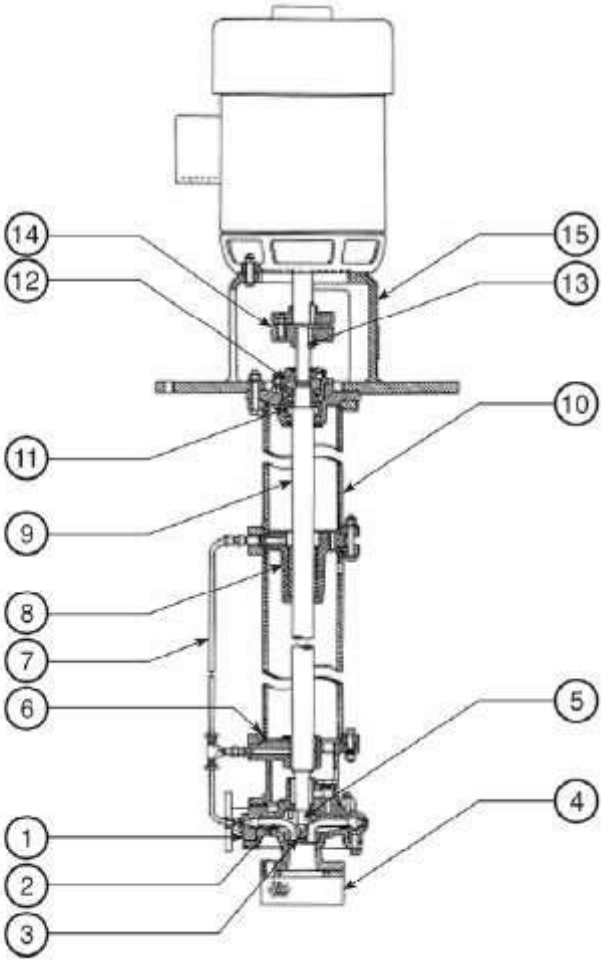



Figure 465. Oil pumps for a large turbine. The top cover of the tank is at “A” with the pumps on located on the cover

## 17. What is left running when the turbine is shut down?

The auxiliary oil pump. During the shut down procedure you should keep a close eye on lubrication. Make sure that the auxiliary oil pump starts (auto) and that this pump is left on until unit cools down. If a turning gear is used lubrication must be provided to the turning gear and this should also be checked.

*S&V page 129*




| Item | Description |
|---|---|
| 1 | Casing |
| 2 | Impeller |
| 3 | Retaining Nut |
| 4 | Suction Strainer |
| 5 | Impeller Key |
| 6 | Lower Bearing |
| 7 | Pump Bearing Oil Supply Line |
| 8 | Intermediate Bearing |
| 9 | Shaft |
| 10 | Outer Column |
| 11 | Thrust Bearing |
| 12 | Bearing Locknut |
| 13 | Coupling Key |
| 14 | Coupling |
| 15 | Motor Support |

Figure 466. Auxiliary oil pump

## 18. Besides lubrication, which are two functions of lubricating oil in some turbines?

In large units, lube oil cools the bearings by carrying off heat to the oil coolers. Lube oil in some turbines also acts as a hydraulic fluid to operate the governor speed-control system.

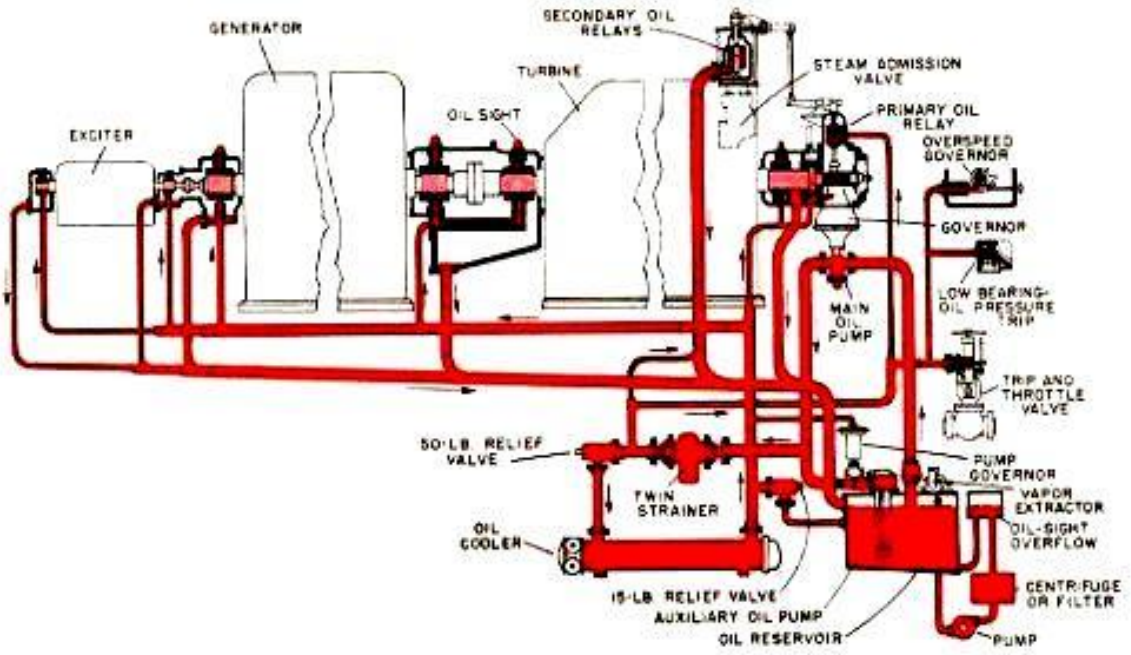



Figure 467.

## 19. Governor mechanisms - extraction valves etc. are operated by what system? Why is this system used instead of a direct system? Where does this oil come from for its operation?

On large turbines, governor mechanisms - extraction valves etc. are operated hydraulically. This method is used because the steam valves are bulky and governors cannot be sensitive and at the same time develop large enough forces to operate valves directly. Oil may come from the turbine lubrication system.

## 20. How is fire prevented from occurring on turbine lube oil systems?

Oil reservoirs of modern turbines are generally located from 10 to 35 feet below the turbine to provide proper drainage from bearings. Turbine manufacturers have agreed to this location. The accessories of the system, oil pumps and coolers, are placed within the tank. Centralization and removal of oil equipment from the turbine level have made possible the trim appearance of present day large units. Locating the tank below all main and extraction steam lines also aids in reducing fire hazard from broken oil lines pouring on high temperature piping. All oil lines are shielded by double piping to prevent oil leaks as a pipe at about 750 to 1000 degrees would cause oil spills to burst in flames.

*S&V page 100 D.E.S.C. "Lubrication Section"*

Figure 468. Looking down below the turbine floor to where the lube oil system is located

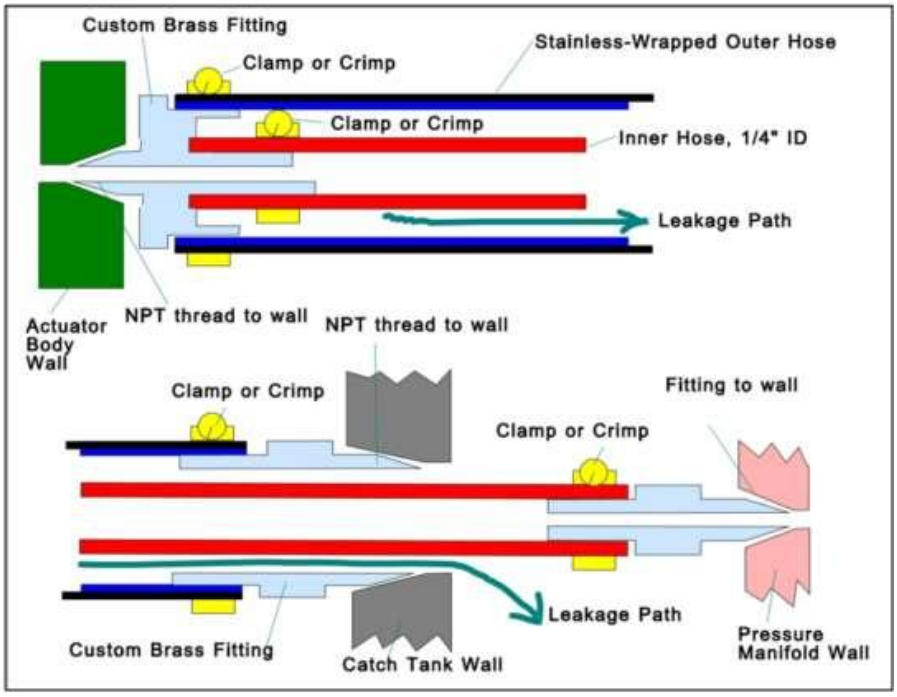



Figure 469. Pipe-in-pipe and hose-in-hose systems for fire protection

Turbine components using hydraulic oil as an operating medium for both lubrication and control require the following basic safeguards to conform to SPCC: All pressurized lines must be guarded by a fully enclosed gravity drain established conducting any leak at any point in the main tank or pressurized line runs to a leakage holding vessel. The leakage holding vessel must have greater capacity then the total oil volume in the system plus twenty percent. A transfer system must be provided for removing oil in the leakage vessel, also using guarded lines. A low leakage risk filling and oil changing transfer system for the operating tank or reservoir, using guarded lines. Guarded lines have been established as "pipe in pipe", "pipe in hose", and "hose in hose" depending upon the working oil pressure. Leakage holding vessels are designed and located such as to collect both guarded line leakage and primary reservoir leakage with level measurement instrumentation alerting operators of a primary system leak.

CASTROL ANVOL PE 46 HR

Figure 470.

Castrol Anvol PE 46HR is a phosphate ester based fire resistant hydraulic fluid (ISO Classification HFD 46R) intended for use in steam turbine governor and boiler control systems.

Figure 471.

Fyrquel® EHC Plus Electro-Hydraulic Control Fluid is a phosphate ester based fire-resistant fluid, and is the latest introduction to the Fyrquel® EH Series. This next generation product features the same superior self extinguishing fire properties exhibited from earlier generation Fyrquel® fluids, while providing added performance and sustainability benefits. These fluids are in the class of "non aqueous hydraulic fluids" and also referred to as "synthetic fire resistant fluids". Fyrquel® fluids are both extremely difficult to ignite and inherently self extinguishing. Other type synthetic fluids are not self extinguishing. Critical equipment should use self extinguishing fluids to get the highest level of protection from leaking fluid fires.

Fire resistant fluids offer much better fire protection than petroleum oils because of their higher ignition temperature of 1380 degrees Fahrenheit compared to 700 degrees Fahrenheit for petroleum oils. There were 97 reported powerplant fires worldwide due to turbine oil ignition between 1972 and 1996. Six of these fires occurred in the United States. The total repair costs for the United States fires was $172 million and caused a total forced outage of 270 days. *Steam turbines for Modern Fossil Fuel Power Plants page 178 by Aleksandr Leizerovich*

Wilsonville, Alabama. Fifteen people were hurt when an oil fire broke out in an Alabama Power Co. generating plant forcing the shutdown of 4 of the plants 5 generators. "The fire began when a leak in the turbine oil system developed" said plant spokesman Mike Casey "The oil is very hot. Somehow it ignited. It might have come in contact with a steam line". Casey said the fire spread to the tanks that hold the oil. *Florence Alabama Times Daily November 16th 1991.*

## 21. What is oil whip?

Modern turbines have been designed with sufficient bearing and rotor stability margin to provide for the normal range of operating conditions. However, changes in alignment, which tend to unload some bearings, can occur during operation. Light bearing loads reduce the stability margin and may lead to an unstable condition known as oil whip. Bearing wear also can increase the tendency toward such instability.

Low oil temperature increases oil viscosity and contributes further to bearing instability. You should make every effort to maintain the vendor recommended oil temperatures during operation (usually 110-120 degrees F.). Also, cool the oil promptly at shutdown, to provide thicker oil films and reduce friction during turning gear operation.

If oil whip should occur, it can be recognized by a characteristic high-amplitude vibration at or below a rotor natural frequency, and at substantially less than running speed frequency.

Since low-frequency vibrations of a given amplitude contain less energy than those of higher frequency, whip frequency vibrations of 10-12 mills of shaft amplitude usually are not dangerous. But they can be annoying. If moderate-amplitude oil whip occurs, and is recognized, it usually is desirable to continue running while controlling the whip by increasing oil temperature or by changing other operating variables.

Under some conditions, sufficient stability margin may be developed so further corrective action is unnecessary, or at least can be postponed until a convenient outage. In other instances, a shutdown may be required in order to change alignment or to accomplish bearing repairs or modifications.

*"Operating and Maintaining Steam Turbine / Generators, Powers Reprint 1976. page 6.*

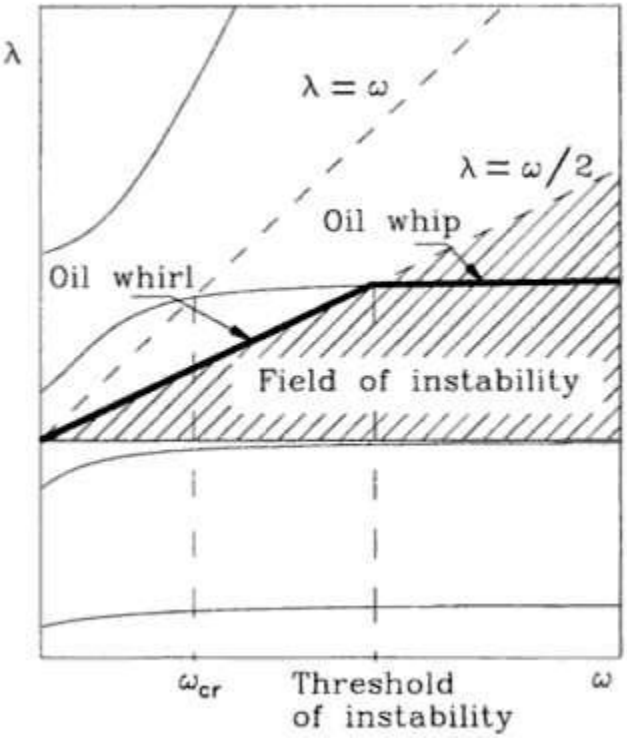



Figure 472. Oil whip diagram

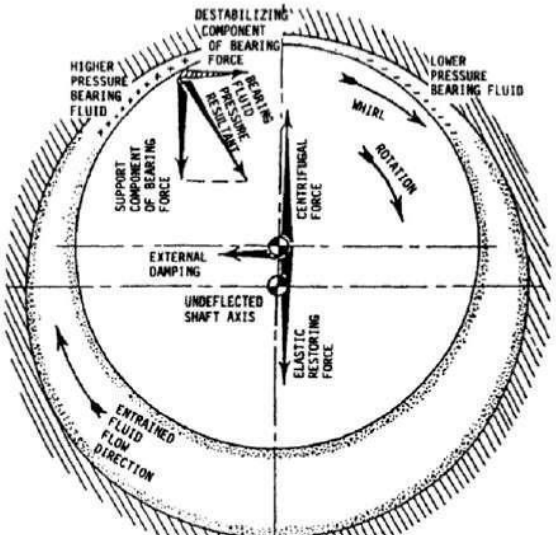



Figure 473. Oil whip causes vibration

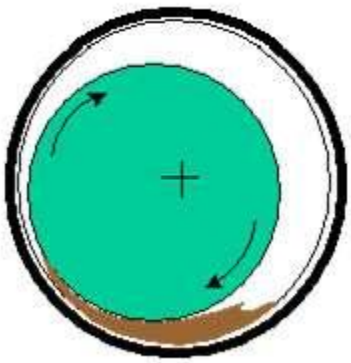


Figure 474. Shaft rotating in oil film

## 22. At what speed does the main oil pump come into play?

The oil pump starts at:

1500 RPM on a 1800 RPM unit.

2700 RPM on a 3600 RPM unit.

## 23. What is an oil ring?

An oil ring is a ring which rides on the journal while its lower arc dips into the oil reservoir. As the shaft rotates, the ring revolves carrying oil to the top of the journal.

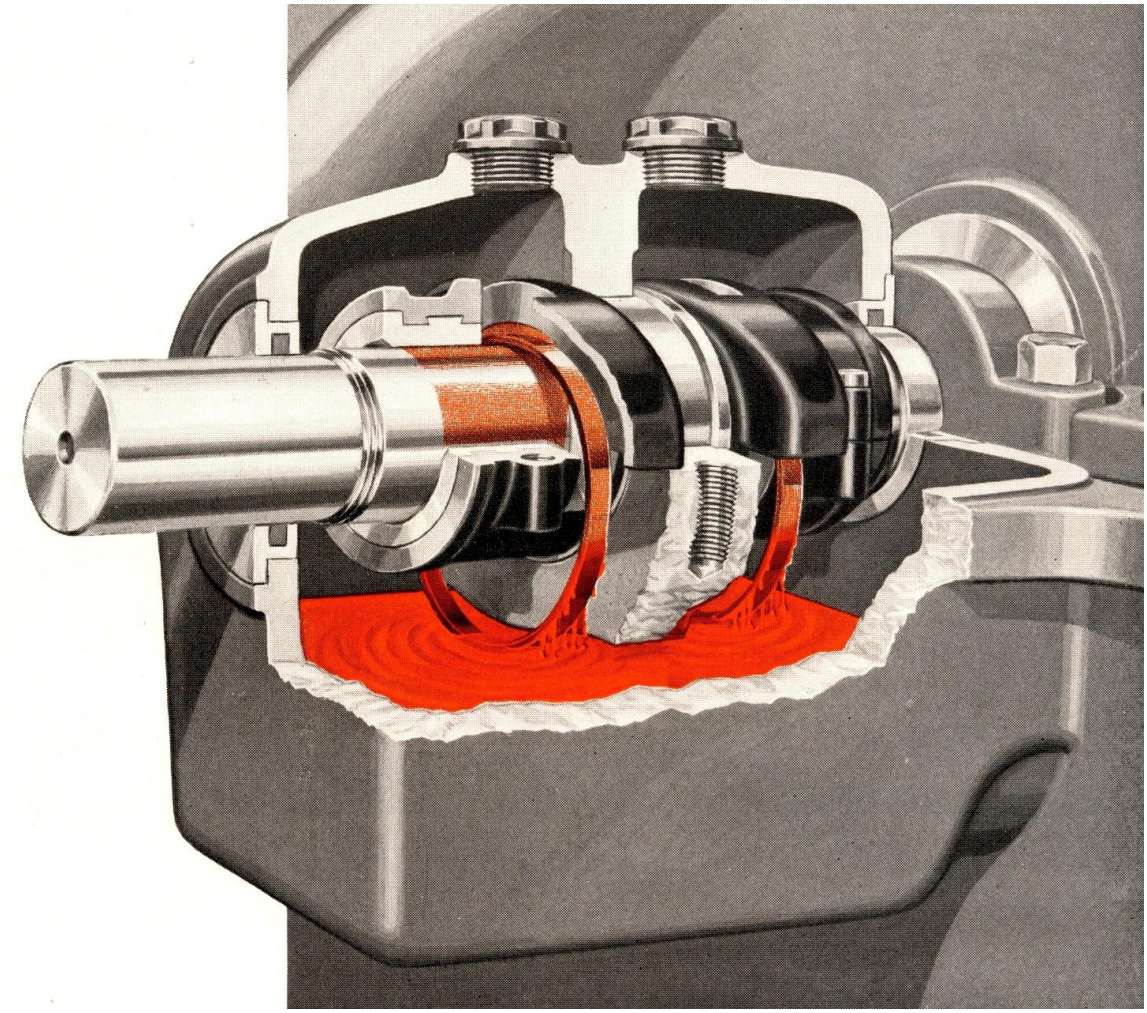


Figure 475. Oil ring dipping into the oil reservoir

## 24. What does the quantity of oil circulated depend on, how is it determined?

The quantity of oil circulated is determined by cooling needs rather than by lubrication requirements. A bubbler oil sight glass gives a visual indication of lube oil flow. A thermometer may be incorporated.

## 25. What are the three jobs lubricating oil does in a turbine?

Three jobs lubricating oil does in a turbine are:

1) It reduces friction losses between all rubbing surfaces, and so reduces wear and improves efficiency.

2) It aids in removing the heat developed in these parts.

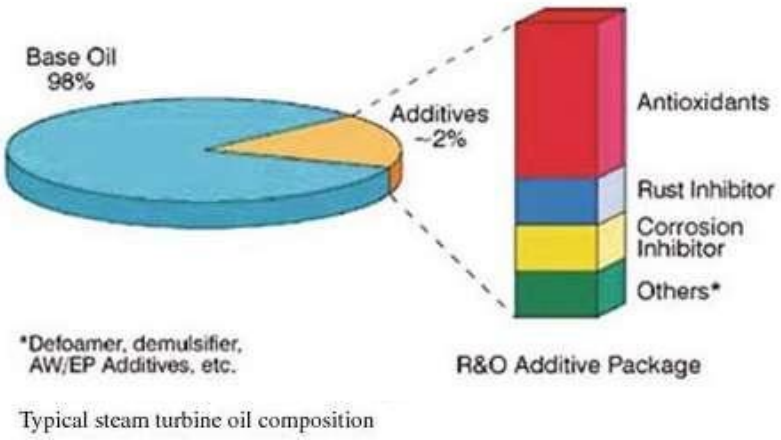
3) It acts as a pressure fluid to operate the governor and stop valves of larger turbines.

## 26. What are the fundamentals of bearing lubrication? What is friction? How many kinds of friction are there?

Friction is the resistance to motion. Two kinds of friction are solid and fluid.

## 27. What type of oil is used for turbine lubrication? What are additives? Why should turbine oils not be mixed?

The type of oil used for turbine lubrication is mineral oil which as not been compounded with animal or vegetable products. Additives are used to improve the oil. Turbine oils should not be mixed because the additives may react with each other and offset their good effect.




Typical steam turbine oil composition

Figure 476.

## 28. What are causes of oil impairment? Explain fully.

a) Moisture: Due to leakage from glands; leaks in oil-cooler tubes; condensation on inner sides of sumps, gearing and bearing castings, and housings. Humidity.

b) Air: Due to leakage in suction line to oil pump; inadequate venting; low oil level so suction line draws air; splashing of oil flowing into reservoir or through cleaning system; air contact with oil in bearing housing.

c) High temperature: Result of insufficient cooling; too little oil; improper oil; mechanical defects of bearing surfaces; incorrect bearing clearances; improper alignment; oil pipes and reservoir too close to casing.

d) Catalytic effect of metals: Metals in contact with oil helps speed up oxidation.

e) Mixing of oils: Results from deliberate mixing or adding new oil when some old oil remains in system. Mixing usually shortens life of new oil but does help new oil to adhere to, or wet, the surface. One per cent old oil can affect this.

f) Foreign matter as dust, dirt, fly ash, core sand, metal particles, or rust.

g) Insufficient oil supply: Due to excessive air or water, dirty strainers, clogged pipes, or too little oil in system.

h) Low oil pressure: Resulting from too little oil in system; faulty relief valves.

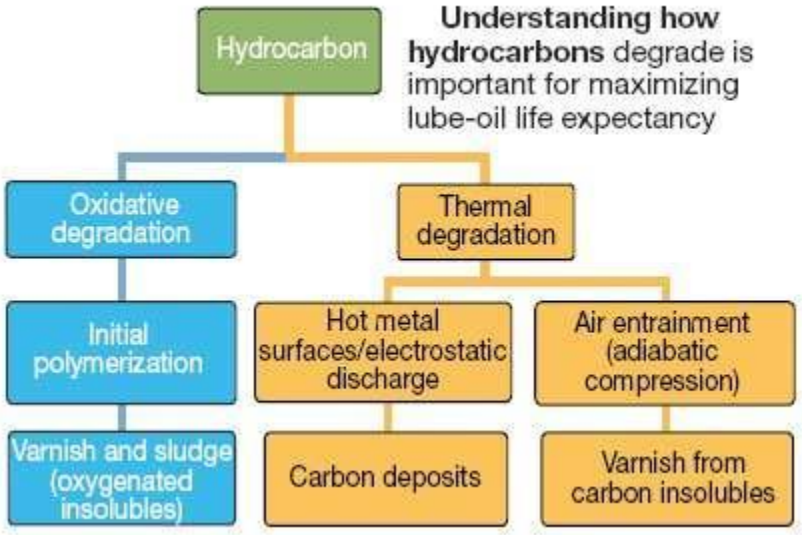



Figure 477.

## 29. What troubles do these impairments cause?

Troubles caused by oil impairment are:

a) Foaming or frothing: Caused by air mixing with oil, or by adding new oil too quickly to the system. It may cause a drop in oil flow to bearings, faulty governor action, or overflow from a system.

b) Emulsification: Caused by mixing of oil and water, usually with air and solids also being present. The effect lowers the lubrication values of oil and may cause deposits to settle out in bearings.

c) Oxidation: This results from air acting chemically on oil. Oxidation is doubled for each increase in oil temp. of 20 F. Oxidation produces such substances as alcohol, ketones, organic acids, and metallic soaps. When these break down, they form sludges which tend to clog oil lines.

d) Corrosion: Caused by presence of water which corrodes gears, governor control mechanisms, journals, pumps, housings, reservoirs, etc. When rust forms as a result of corrosion, it often gets in oil and has an abrasive effect; some forms also help oil to oxidize.

e) Sludges and deposits: The results of oil oxidation and also foreign matter getting into a system. They act to clog flow lines; cover cooler surfaces; become abrasive on bearing surfaces; and clog governors and other valve mechanisms.

Elimination depends on retarding oxidation; stopping entrance of foreign matter; and removing the deposits that form despite proper oil maintenance.

## 30. What methods are used for reconditioning of turbine oils? Explain fully.

Methods used for reconditioning of turbine oils are:

a) Settling or precipitation tank: The simplest means of clarification is to allow the used oil to stand in a tank quietly for a period from one day to one or more weeks. Settling is mainly intended to remove water and heavier sludges. Gravity alone causes the separation. Tanks are usually equipped with steam heating coils as the warmer, less dense oil clarifies more easily.

b) Centrifuges: Used to remove water, solid matter, and some of the water-soluble oxidation products. Dirty oil is fed to a rapidly rotating bowl. Centrifugal force tends to throw solid matter and water, which are both heavier than oil, to the walls of the bowl.

c) Filters: The three types are as follows:

1. Strainers: Made of screens, metal disks, steel wool, copper ribbons, cloth, or blotting paper. They filter out coarse solid impurities. Blotter filters also remove water.

2. Absorbent filters: Made of cotton waste and other absorbent cellulose material; some also take out water and mineral acids.

3. Adsorbent filters: Use a filter medium of fullers earth, diatomaceous earth, charcoal, or other similar material. They remove coarse and fine material; also water and some soluble oxidized material.

d)Washers: Oil can be cleaned of many of its oxidized impurities if it is passed through a water bath since most impurities are more soluble in water than in oil.

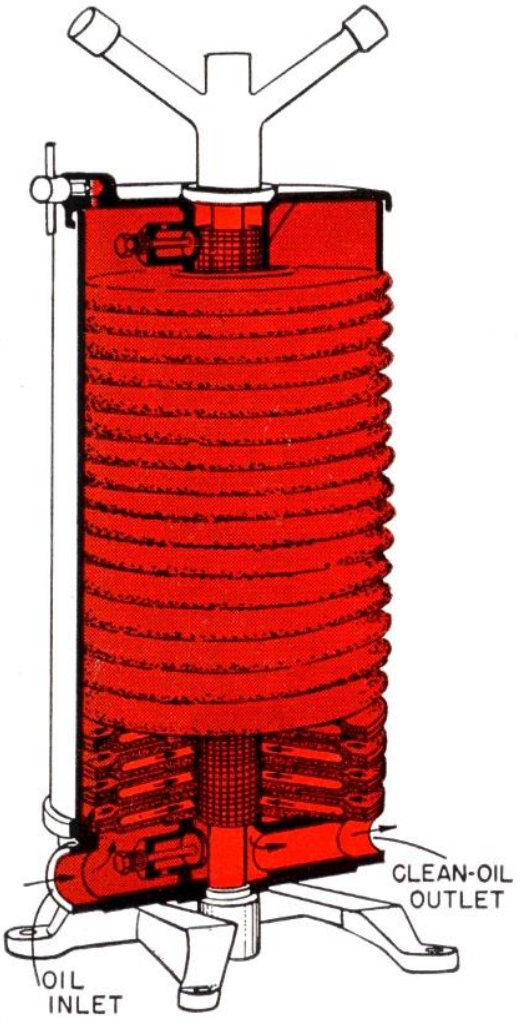



Figure 478. Oil filter assembly for a steam turbine

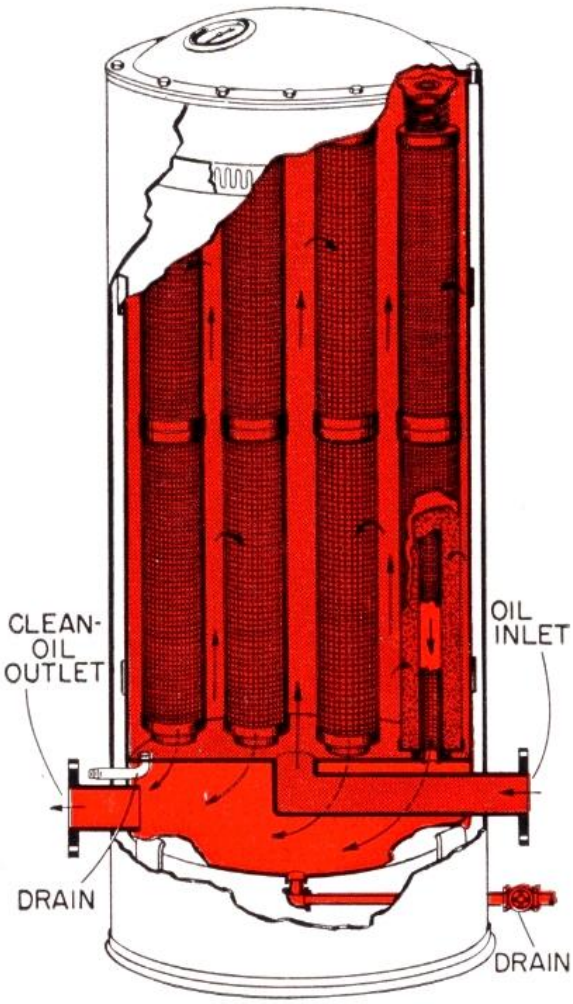



Figure 479. Another style of oil filter

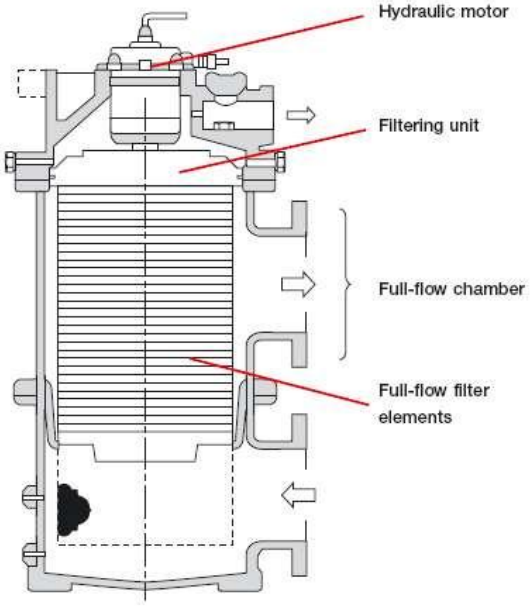



Figure 480. Spinning disc filter

Figure 481. Replacement discs for the spinning disc filter

Figure 482. Large filter housing

Figure 483. Large screen. This particular screen is disintegrating. Screens must be checked and cleaned often

Figure 484. Oil Reclamation Unit

## 31. What methods are used for oil maintenance systems? Explain fully.

The methods of oil maintenance systems are:

a)Make-up: Small ring-oiled turbines are most commonly lubricated by adding oil to the system periodically to make up for lube-oil losses.

b) Sweetening: In this method about 10% of the oil in the system is withdrawn at intervals from the bottom of the oil reservoir and sump. New make-up oil is added. This method is not favored for turbines because is allows old oil to deteriorate between sweetenings.

c) Batch treatment: This method uses settling tanks to treat the entire batch.

d, e, and f) Flow treatments:

d) Better results are obtained in oil maintenance if oil charge is treated continuously.

e) Instead of passing the entire oil flow (continuous treatment) handled by the main turbine lube-oil pump, through a cleaner, such as a centrifuge, filter, or conditioner, only part of the oil (continuous by-pass) is treated.

f) Also a combination by-pass and batch treatment method is used. This is a better method since some oil contaminants are soluble at operating temperatures, but precipitate out when allowed to stand in tanks at room temperature.

## 32. Explain types of lubrication systems used on turbines.

A. For direct drive turbines:

1. Ring oiling - a ring rides on the journal and its lower arc dips into the oil reservoir as it rotates with the shaft.

2. Circulating (pressure or gravity)

B. For geared turbines:

1. Self-contained splash system where lower half of gear is immersed in oil.

2. Self-contained circulation system, has oil reservoir in lower housing with provision for cooling the oil by water chambers or coils. A pump delivers oil to the bearings and, through spray nozzles, to the gears.

3. Turbine main circulation system.

Figure 485. Large reduction gear unit

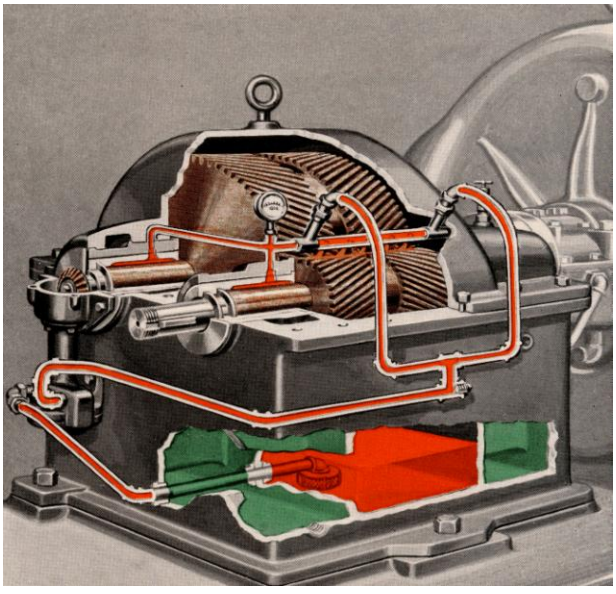
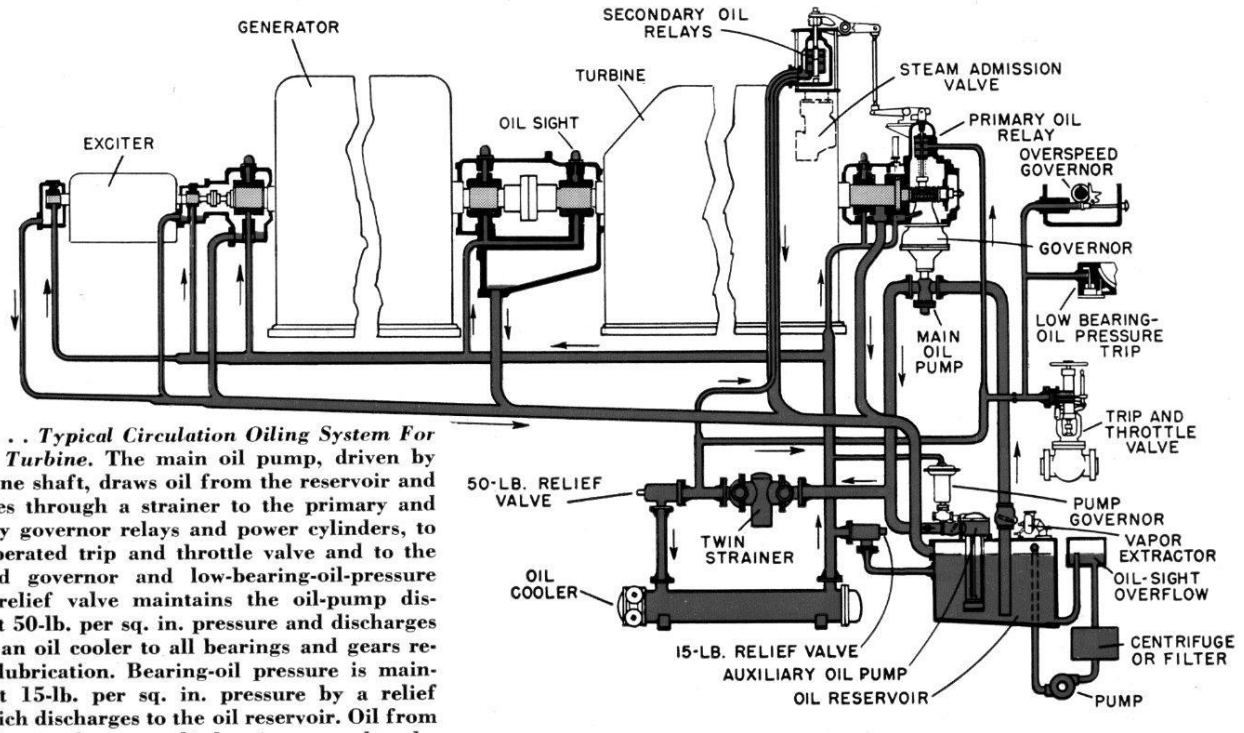


Figure 486. Oiling system for reduction gears




***. . . Typical Circulation Oiling System For a Steam Turbine.*** **The main oil pump, driven by the turbine shaft, draws oil from the reservoir and discharges through a strainer to the primary and secondary governor relays and power cylinders, to an oil-operated trip and throttle valve and to the overspeed governor and low-bearing-oil-pressure trip. A relief valve maintains the oil-pump discharge at 50-lb. per sq. in. pressure and discharges through an oil cooler to all bearings and gears requiring lubrication. Bearing-oil pressure is maintained at 15-lb. per sq. in. pressure by a relief valve which discharges to the oil reservoir. Oil from the bearings and power cylinders is returned to the oil reservoir. The auxiliary oil pump, used during starting and stopping, discharges through a check valve into the main-oil-pump-discharge piping. An overflow line from the bottom of the reservoir discharges to a centrifuge or filter, and the clean oil is returned for reuse by a separate pump. A vapor-extractor is provided for ventilating the reservoir.**

Figure 487.

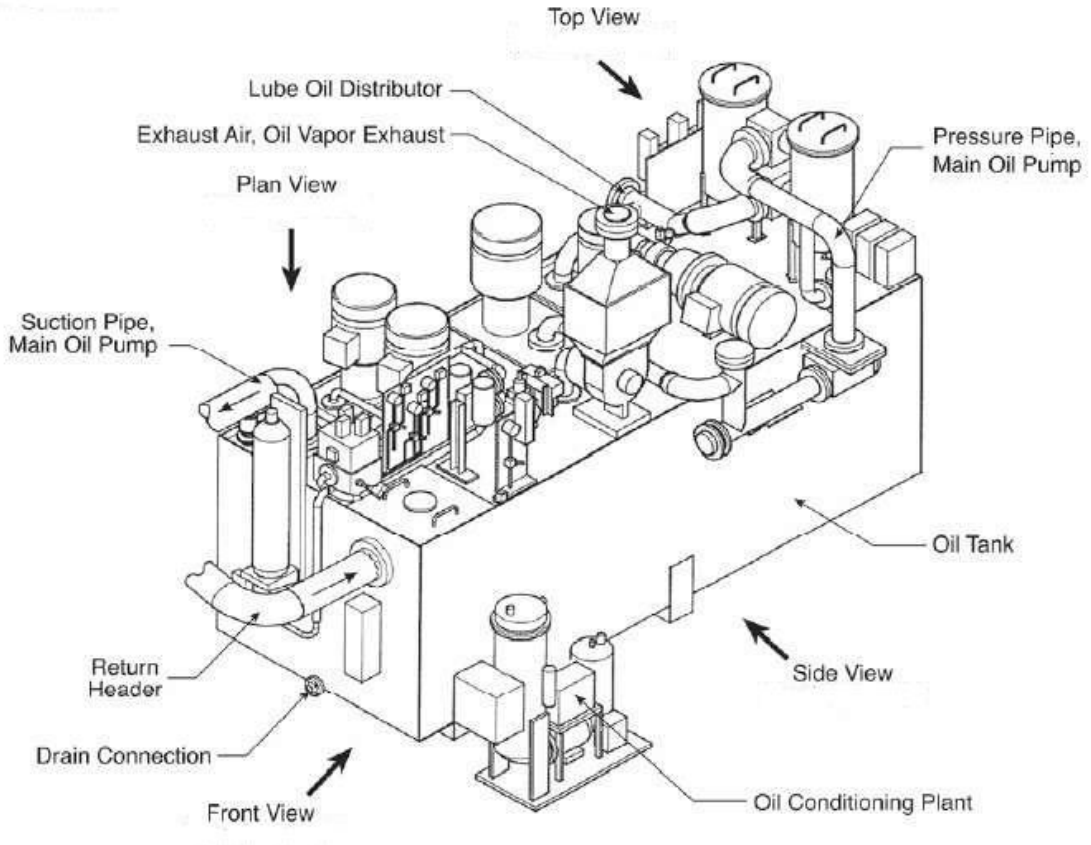



Figure 488. Oil reservoir tank, pumps and piping, isometric view

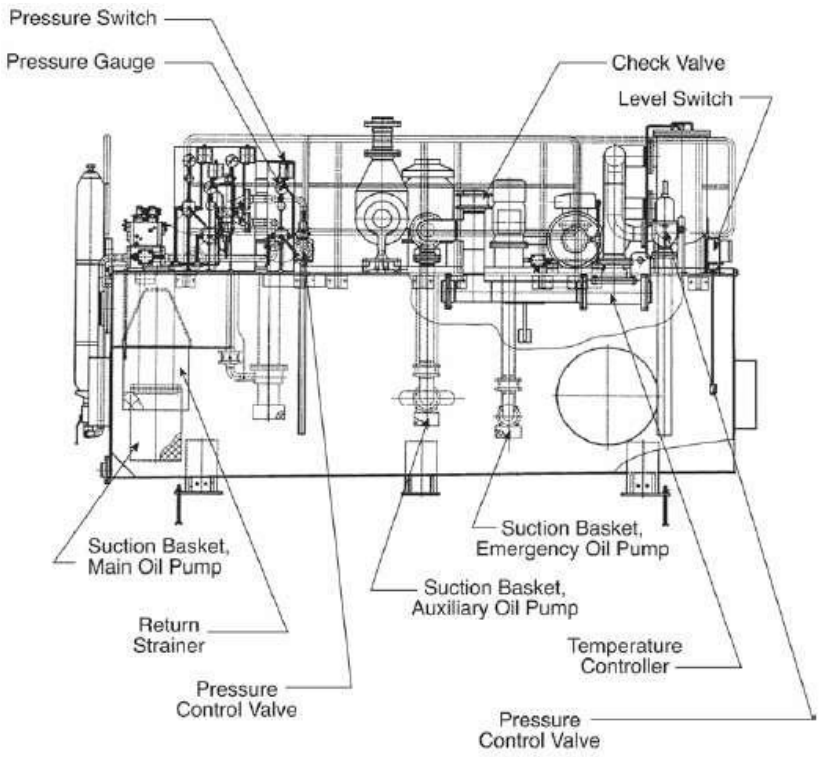



Figure 489. Oil reservoir tank, pumps and piping, side view

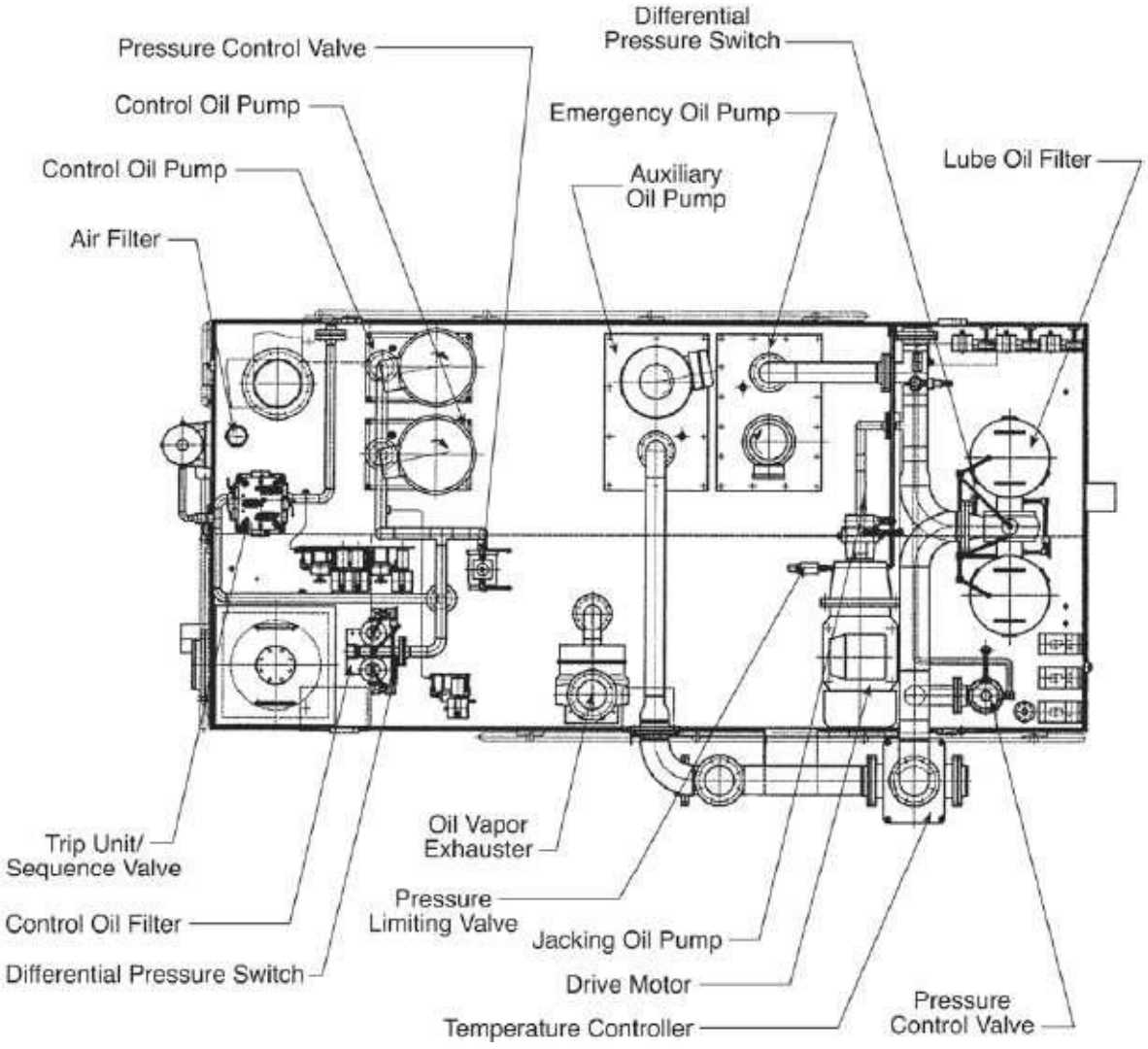



Figure 490. Oil reservoir tank, pumps and piping, top view

## 33. Whose recommendations should you follow in the use of oils?

Manufacturers' recommendations for the different types of oil are best followed in all cases.

In general, what basic procedures on the care of lubrication systems are used?

A. Practice a regular method of purifying oil.

Maintain treatment equipment in good order.

B. Clean oil strainers regularly, usually daily.

C. Drain bottom of oil reservoir daily to remove water and other contaminants.

D. Check on water leakage by inspecting the turbine steam & water glands, and oil cooler.

E. Check on oil leakage by inspecting the bearing seals and oil piping.

F. Follow manufacturer's recommendations for periodic cleaning & overhaul.

G. Check oil level daily, and keep a record of type and quantity of make-up oil added.

H. In starting, follow manufacturer's recommendations, but check on whether main oil pump is functioning and whether correct oil pressure is developed.

I. Take oil sample weekly for visual check. Take oil sample about every 2000 hr. of operation for lab analysis.

J. Keep daily log of all oil pressures to governor and bearings.

K. Keep daily log of water temperatures.

L. Keep daily log of oil temperatures.

M. Keep a log of all maintenance items.

Figure 492. Oil sample

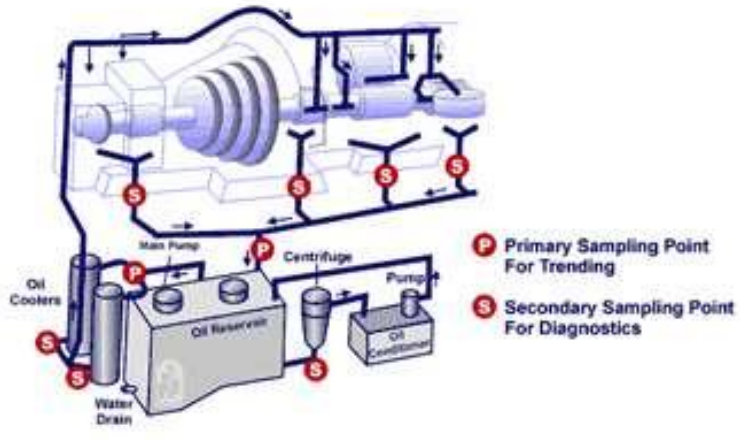



Figure 491. Places for taps to get oil samples. Each oil sample tap should have a pipe plug in the outlet after the valve to prevent oil leaks after sampling.

## 34. What should be done before starting a new turbine?

Before starting a new turbine it is necessary to make certain that the lubrication system is absolutely clean. Manufacturer's instructions are to be followed for starting. The following are recommended as a guide to correct procedure:

A. Inspect and clean, with compressed air, all oil and water piping.

B. Add a small amount of oil to reservoir, circulate with aux. oil pump for about one hour then drain and clean the system.

C. Fill system and circulate oil for about 8 hours with the turbine idle, check oil pressure, level, and gages. Then allow to set for 10 hours and drain the dirt from the reservoir. Replace the amount of oil drained.

D. Bring turbine up to speed and check everything. Start cooling water when oil reaches 110 to 120°

E. Bring quickly up to 130° to 140° F. and continue checking.

F. After a service period of 300 hrs., unless turbine has a continuous by-pass filtration system, the system should be drained.

One big advantage of turbines is their relatively small consumption of lubricating oil, but even this small amount is very important. What can you add to your answer to question at this point in more detail?

The selection of oil with the proper characteristics is very important. An improper selection can be as fatal as no oil at all.

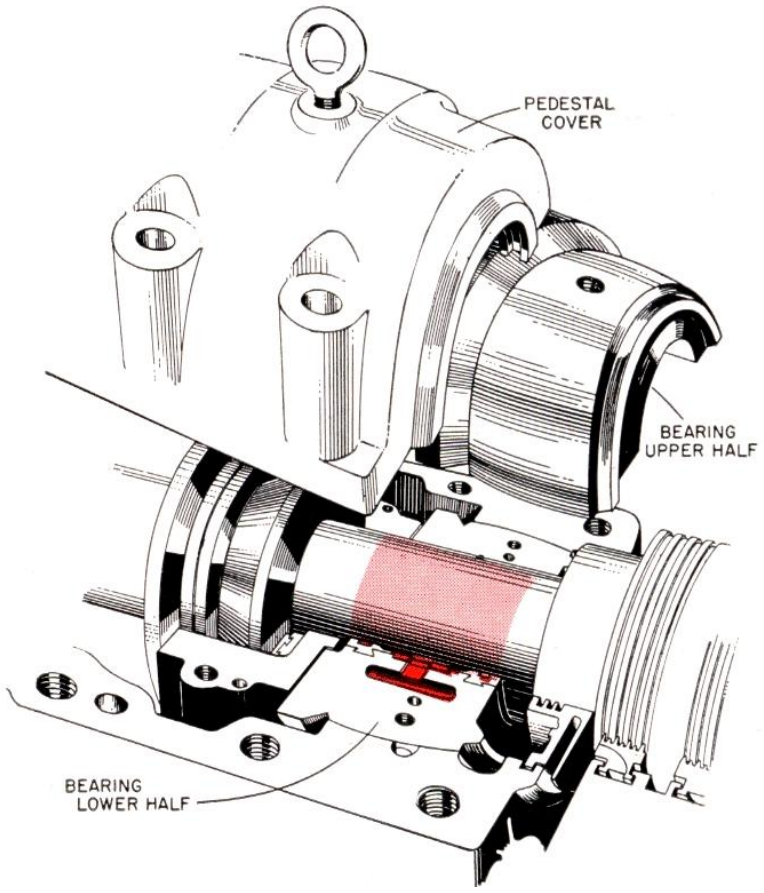



Figure 493. The proper way to prepare the bearing for maximum oil flow before flushing the oiling system is to lift the pedestal covers and remove the upper half of the bearing. Replace the pedestal cover and flush completely.

# Chapter 12 Main Bearings

## 1. Explain a typical main journal bearing used on small turbines.

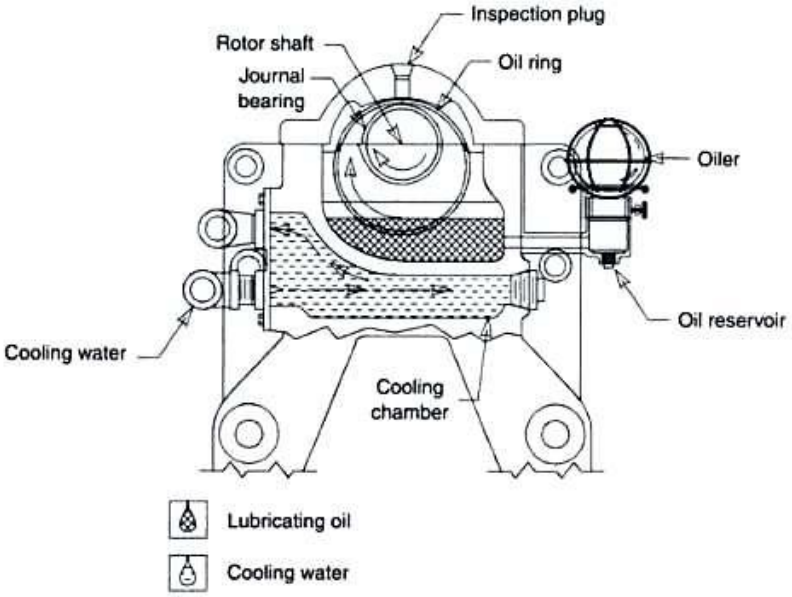
Main bearings support the shaft or rotor of the turbine. On small turbines they are horizontally split babbitt lined with bronze or cast iron shells. Lubrication is supplied by oil rings bringing oil from the bottom of the housing over the bearing.

Single or double row ball bearings are also used on small turbines.

Small turbine bearing housings may be made with passages for cooling water.

*S&V page 66*

Figure 494.



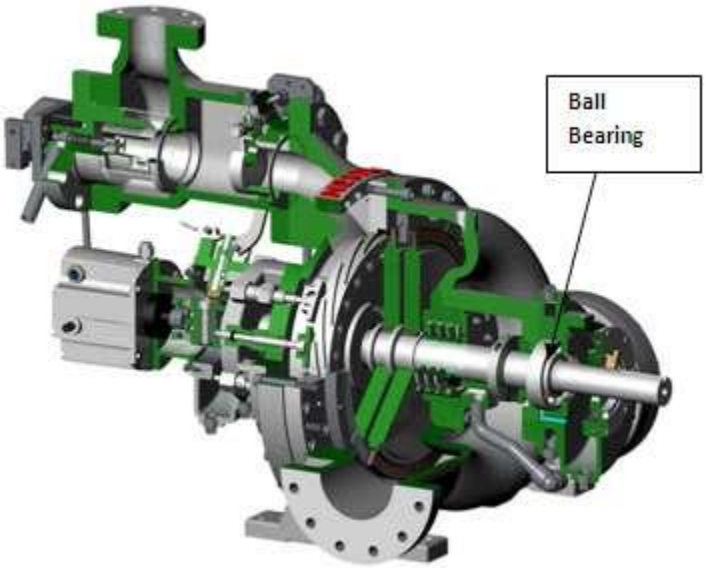
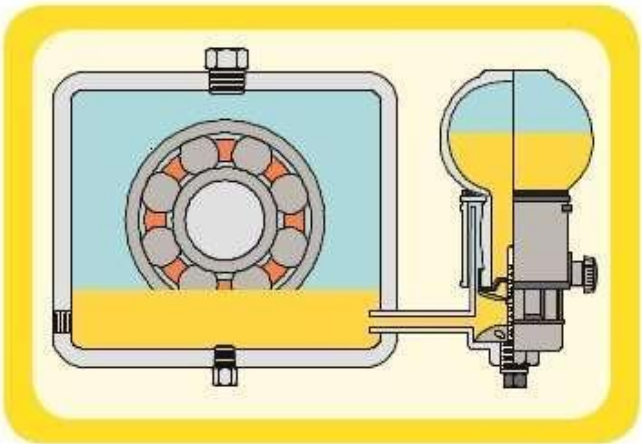



Figure 496. Ball bearings on small turbine

Figure 497. Double row ball bearings

Figure 498. Double row roller bearings



Oil Bath Illustration

## 2. Explain a typical main journal bearing used on large turbines.

A typical main journal bearing for large turbines has a cast shell of steel, split horizontally, with a babbitt lining. Four steel blocks or keys are machined to fit a spherically bored seat in the pedestal, permitting self-alignment. Oil under pressure comes through one of the blocks and is distributed by longitudinal groov shell fits a notch on the pedestal and preve

Figure 499. Oil bottle for a ball bearing. The glass is removed, turned upside down, refilled with oil, and then quickly replaced by flipping it back into position. The side screw is then retightened

Main bearings for large turbines use a cast steel shell lined with babbitt. Oil for the bearings is always supplied under pressure and provides cooling and lubrication. Liners or shims are provided on large turbine bearings as a means of aligning the shaft vertically or horizontally to adjust clearances between the wheels and the casing. The oil film is 1/1000 to 2/1000 per inch of journal diameter. Oil temperature rise across bearings is 20 to 30 degrees. This provides cooling for the bearings.

*S&V page 65, D.E.S.C. Lubrication Section page Kents 11th page 8-42*

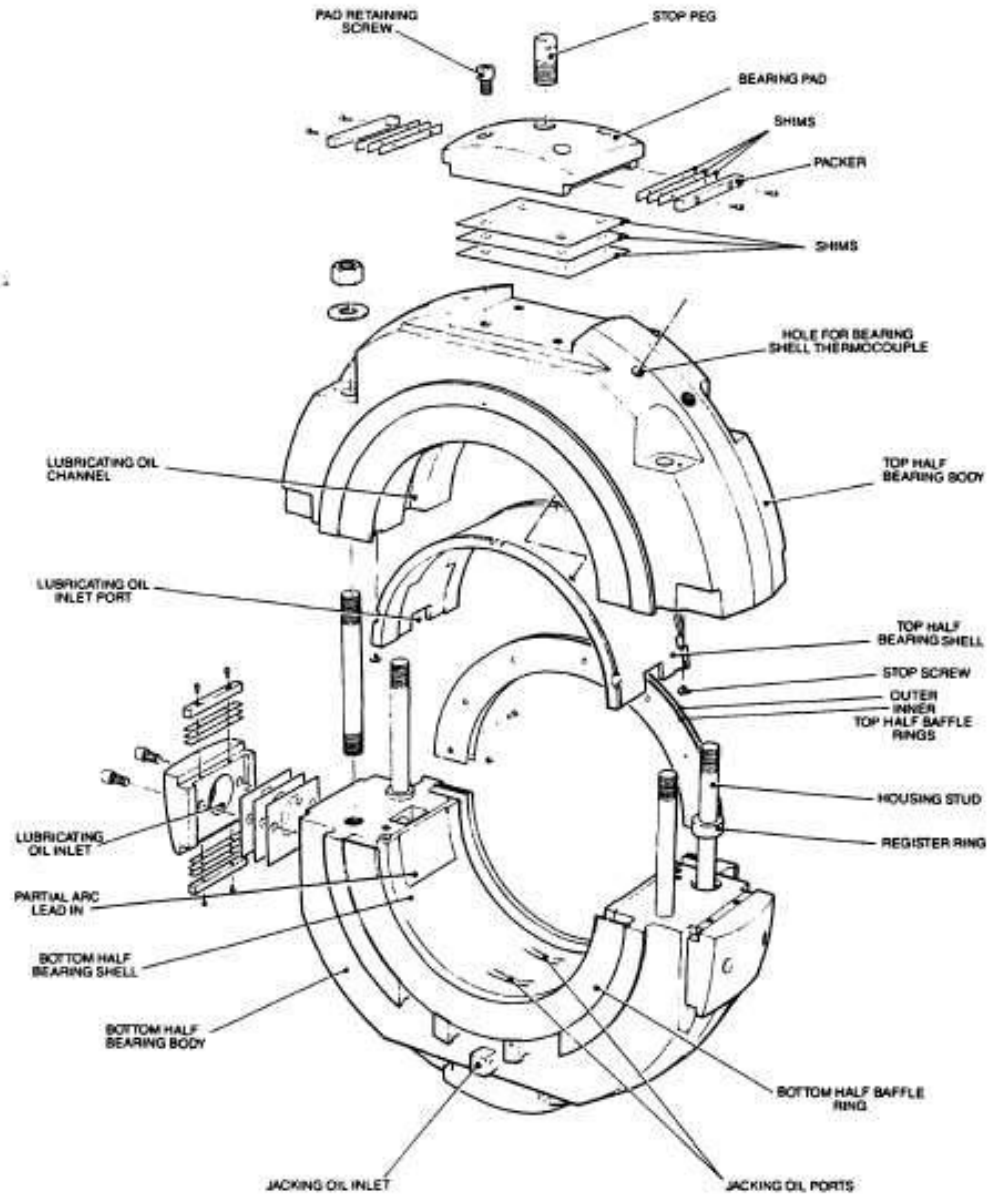



Figure 500. Large journal bearing exploded view

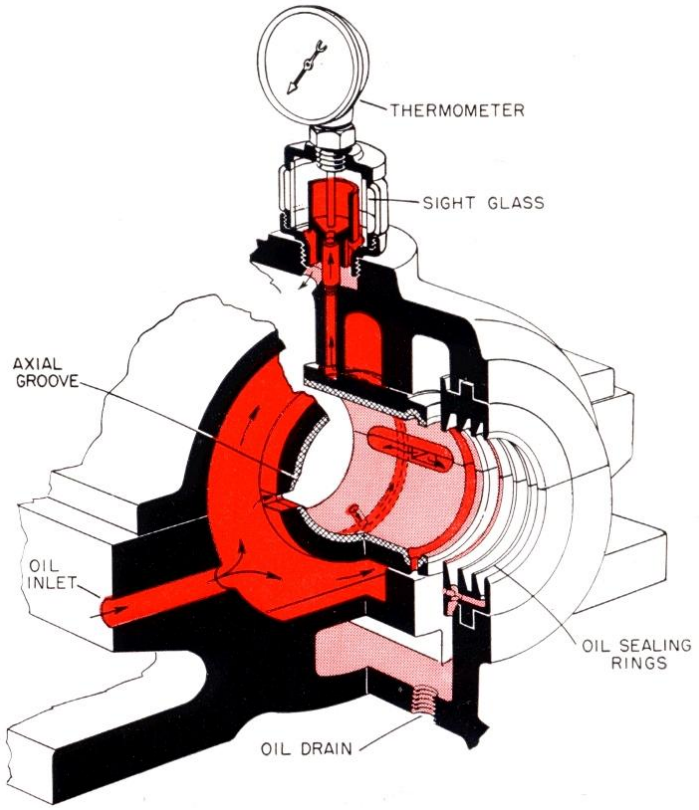



Figure 501. Journal bearing showing the oil path. Oil is supplied to a passageway that completely surrounds the center of the bearing. The oil then flows to axial chamfered recesses into the clearance wedge shaped cavity to form the oil wedge. These cavities are cut into the babbitt.

Figure 502. Heating the babbitt in an electric pot and skimming off the dross that rises to the top.

Figure 503. Pouring molten babbitt

## 3. What is babbitt?

Babbitt is a bearing lining made of lead, tin, zinc, etc.

## 4. Explain all the steps to renew the babbitt in a large bearing.

Melt out the old lining, taking care not to burn the bearing boxes. Clean the interior of the bearing boxes and check to see that they are equipped with the necessary anchors to hold the new babbitt. Bolt the two halves of the bearings together with the necessary shims.

Obtain a mandrel slightly smaller than the shaft or journal on which the bearing is to operate. Center the mandrel with respect to the bearing. Apply a light coating of graphite and cup grease to the mandrel to prevent the babbitt from bonding. Plug up all oil holes and openings to prevent the babbitt from running out.

Before the babbitt is poured, the entire bearing should be heated to approximately 150°F. The babbitt metal must be supplied with a single pour. If the ladle does not hold sufficient babbitt, a second one must be ready and, once started, the pouring continued until the job is complete.

When the babbitt is cool, disassemble the bearing, and hammer (peen) the metal into the recesses. Reassemble with the desired thickness of shims and bore to size in a lathe. With some types of bearings, such as solid-end connecting-rod bearings, it is necessary to make a jig to hold the boxes together while babbitting and boring. After doing this, cut oil grooves in both halves of the bearing in order to direct the oil toward the middle. Do not cut the oil grooves too wide, as this would reduce the effective bearing surface. Relieve the bearing ½ inch or more from the joint to prevent binding in the event of overheating. Now cover the shaft with Prussian blue, which is a dark-blue pigment and dye, assemble the bearings, and rotate. Disassemble and scrape off the high spots as indicated by the Prussian blue on the bearings. Continue this operation until a good bearing surface has been obtained. Observe the bearing for overheating when it is placed in service. Operate at low speed for several hours.

*Woodruff & Lammers 6th Ed. p. 456*

Steam turbines bearings are not "off the shelf" replacement items. Most of these bearings are of babbitt metal. Babbitt metal is a white anti-friction alloy, composed of copper, antimony and tin. Replacing a babbitt bearing requires removing the old bearing and repouring a new bearing. The necessary procedure to perform this task, usually done in the field, follows.

Remove old babbitt by chipping with a chisel and hammer. Wire brush the bearing box clean when all the babbitt has been removed. Tin the casting. If the bearing box is cast iron, coat with a flux and tin with 50/50 solder. Reassemble the bearing boxes with shims in place and place the assembly in a vertical position.

Dam up around the bearing box assemble sides and top with fire clay. Machine a mandrel at least 1/16" smaller in diameter than the shaft or journal that is to be used in the finished bearing. Coat the mandrel with fire clay and water or fine chalk dust to prevent the babbitt from adhering to the mandrel. Insert the mandrel in the assembly and heat the mandrel to about 250 F. Using a ladle big enough to hold all the babbitt metal necessary to make the bearing in a single pouring, heat the babbitt until it melts, usually 500 F to 700 F, then pour the babbitt into the assembly in a thin stream.

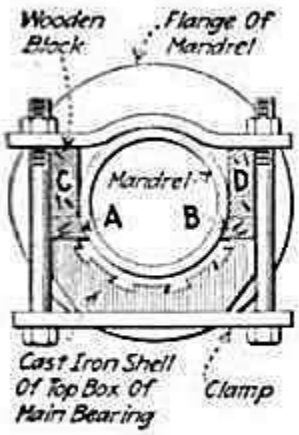
After the babbitt has been poured, cover the surface of the molten metal exposed with a layer of powdered charcoal to prevent dross or bubbles forming. After the babbitt has cooled and set, tap out the mandrel after the bearing halves have been disassembled. Machine and chamfer the ends and edges of the bearing halves.

*D.E.S.C. Steam Engine Operation and Maintenance, page 8*

Freshly re-babbitted bearings should be peened and finished. The metal should be forced tightly into the grooves by striking the inner surface with a peening hammer. The bearing should then be bored to size with a jig or lathe. Now three or four oil grooves about 1/4 inch wide should be chiseled or filed in the babbitt to distribute the oil from the oil holes over the face of the bearing. Finally, the bearing should be "scraped in."

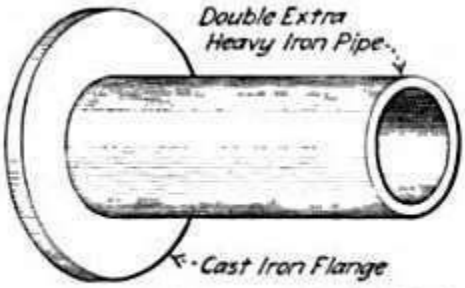
Explanation. - In scraping a bearing, a portion of the shaft is coated with a very thin layer of red lead and oil. The bearing is then placed against the coated portion of the shaft and rotated a few degrees around the shaft. The "high spots" of the bearing are thus coated with the red lead. Then with a scraper these high spots are scraped off. Care must be exercised to insure that the scraping tool does not cut deep into the babbitt metal. The shell should again be coated by spreading the red lead to the spots from which it was removed, and the bearing again applied to it. It will be noted that now more high spots appear than before. These are again removed by scraping. After repeated scraping and marking it will be found that the bearing will bear marks all over its surface and that the unmarked surface is very small. When no large unmarked surface appears, the bearing is ready to be placed into position on the engine. Bearings which are properly scraped will need little "running in" and are not likely to heat or knock when properly adjusted.

*Croft Steam Engine Principals and Practice, 1st Edition, pages 398- 400.*



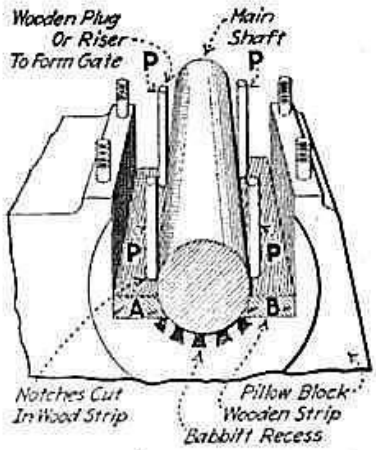

**Main-bearing box clamped to babbitting mandrel.**

Figure 504.



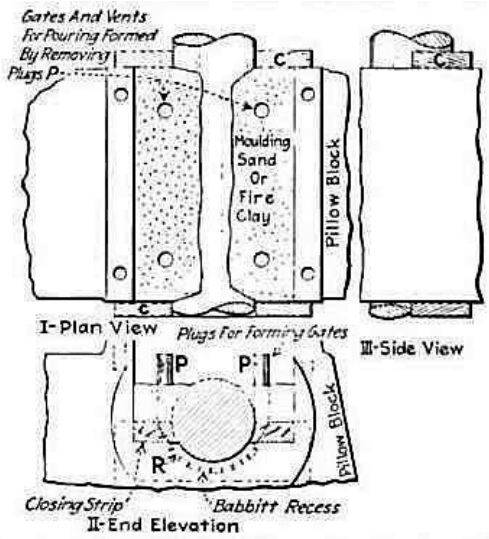

**Mandrel for use in babbitting main bearings.**

Figure 505.



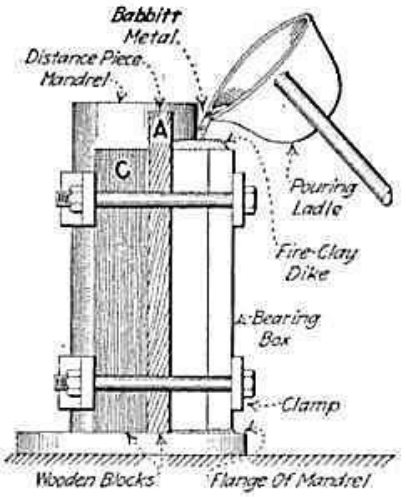

**Showing method of closing, gating and venting babbitt recess in pillow block when re-babbitting a non-removable bottom shell. A bearing so prepared is tamped with moulding sand or fire clay as shown. The plugs, *P*, are set into notches in *A* and *B*, which notches later form gates for the babbitt.**

Figure 506.



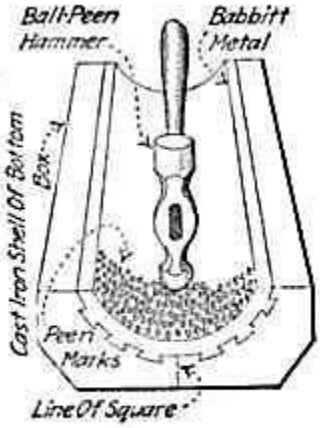

Tamping of journal with molding sand or fire clay. The plugs, *P*, are withdrawn and, after the ends of the babbitt recess, *R*, are closed with wooden collars, *C*, the bearing may be poured.

Figure 507.



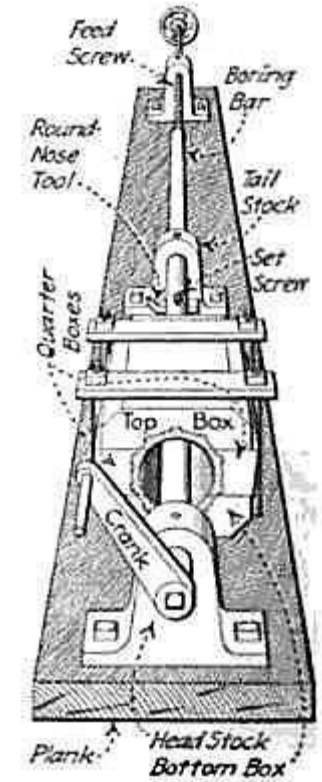

Pouring a main bearing box.

Figure 508.



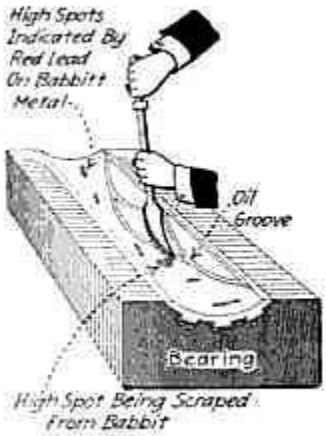

"Peening in" a main-bearing box.

Figure 509.



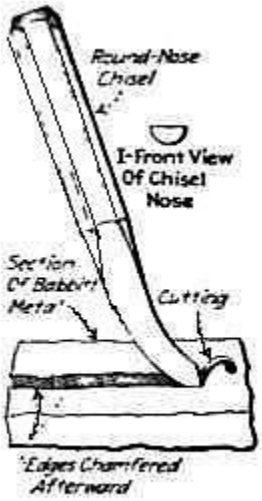

Improvised jig for boring babbitted bearing boxes

Figure 510.



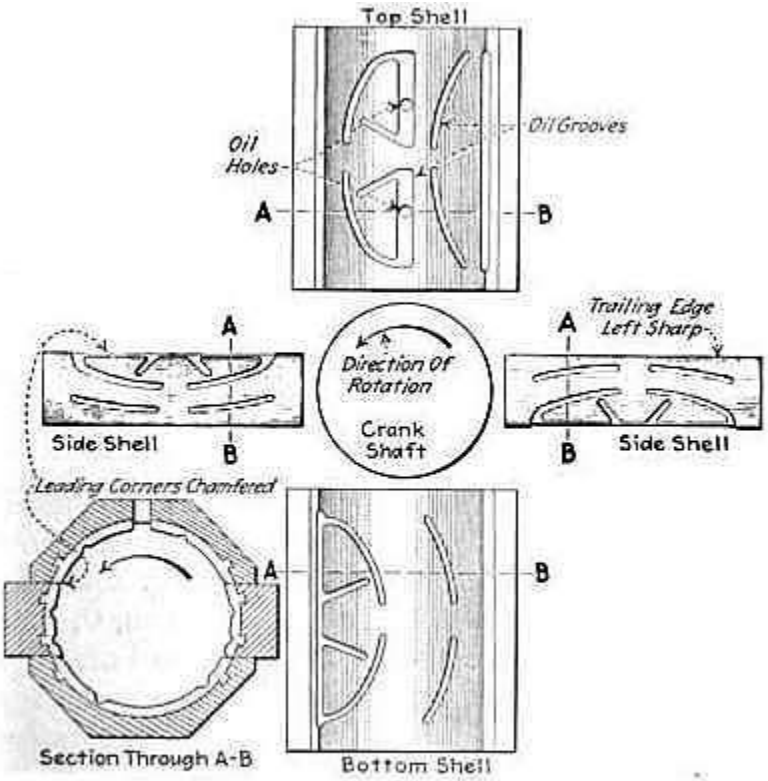

Illustrating method of scraping high spots from a bearing quarter.

Figure 511. You must always wear a suit when scraping the babbitt




Cutting an oil groove.

Figure 512.




Correct oil grooves for main bearing. Note that the grooves are cut for a given direction of rotation. They first distribute the oil and then re-collect it to prevent it from running from the ends of the bearing. Only the leading edges of the bearing shells are chamfered.

Figure 513.

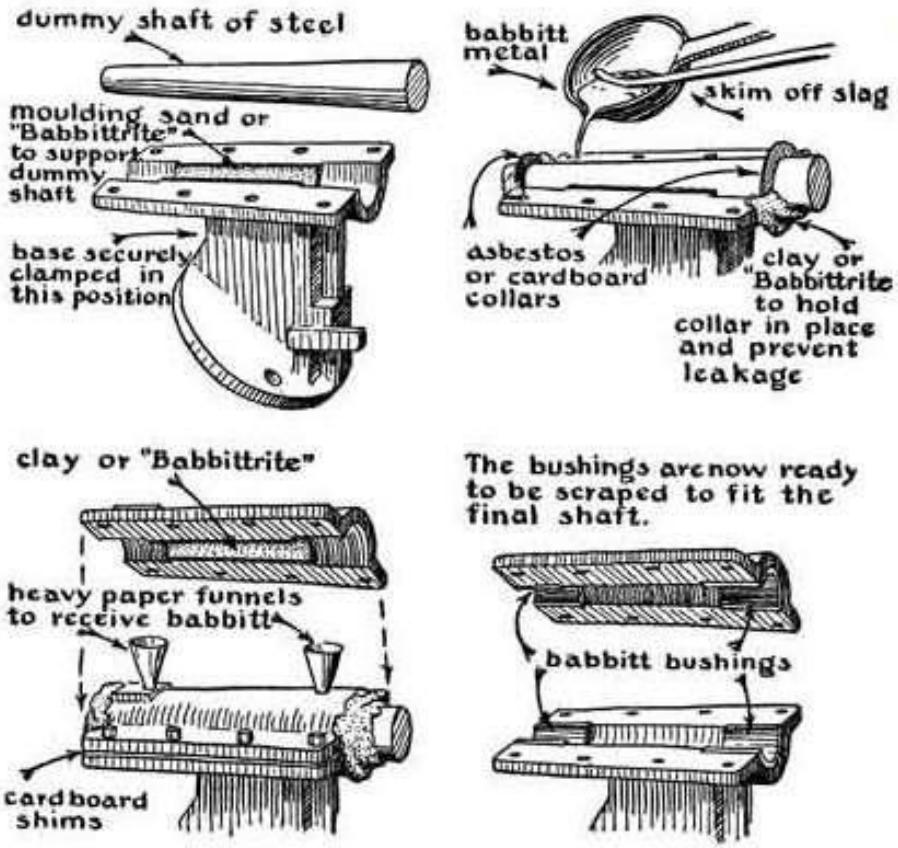

dummy shaft of steel
moulding sand or "Babbittrite" to support dummy shaft
base securely clamped in this position
babbitt metal
skim off slag
asbestos or cardboard collars
clay or "Babbittrite" to hold collar in place and prevent leakage
clay or "Babbittrite"
heavy paper funnels to receive babbitt
cardboard shims
The bushings are now ready to be scraped to fit the final shaft.
babbitt bushings
A dummy shaft must be used because the uneven heating by the babbitt metal might warp the finished shaft and ruin it.

Figure 514.

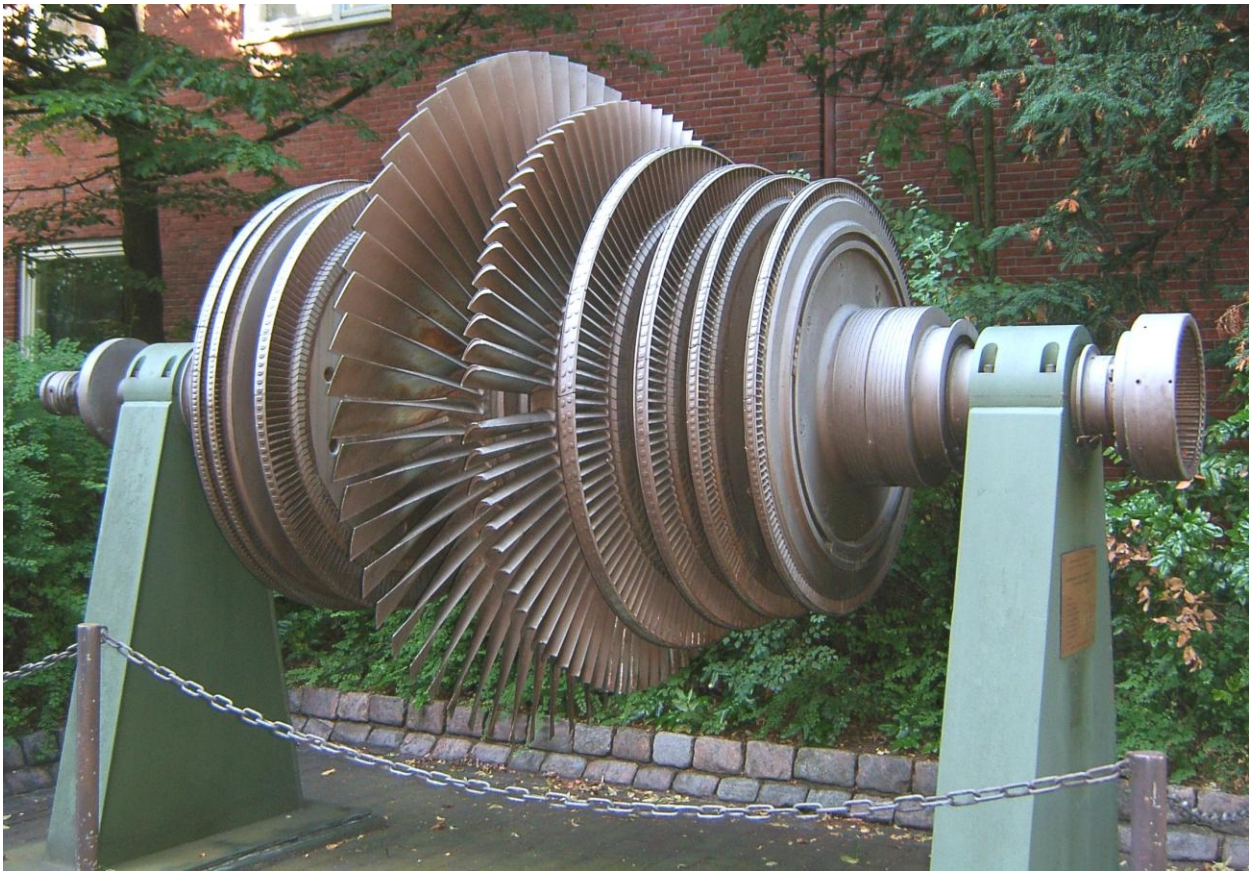


Figure 515. Showing how the turbine shaft rests on two journal bearings

## 5. What is important to remember about radial bearings?

A turbine rotor is supported by two radial bearings, one on each end of the steam cylinder. These bearings must be accurately aligned to maintain the close clearance between the shaft and the shaft seals, and between the rotor and the casing. If excessive bearing wear lowers the rotor, great harm can be done to the turbine.

## 6. What clearance is given for journals?

The clearance given to journals is about .001 to .002 inches per inch of journal diameter.

## 7. How is bearing pressures obtained?

Bearing pressure in psi is obtained by dividing the total load per bearing by the projected bearing area.

### 8. What is the limit per unit bearing surface at present?

A unit bearing pressure of about 200 psi is the upper limit at present.

### 9. What determines the size of the turbines main bearings?

Turbine bearing size is determined by the diameter of the rotor.

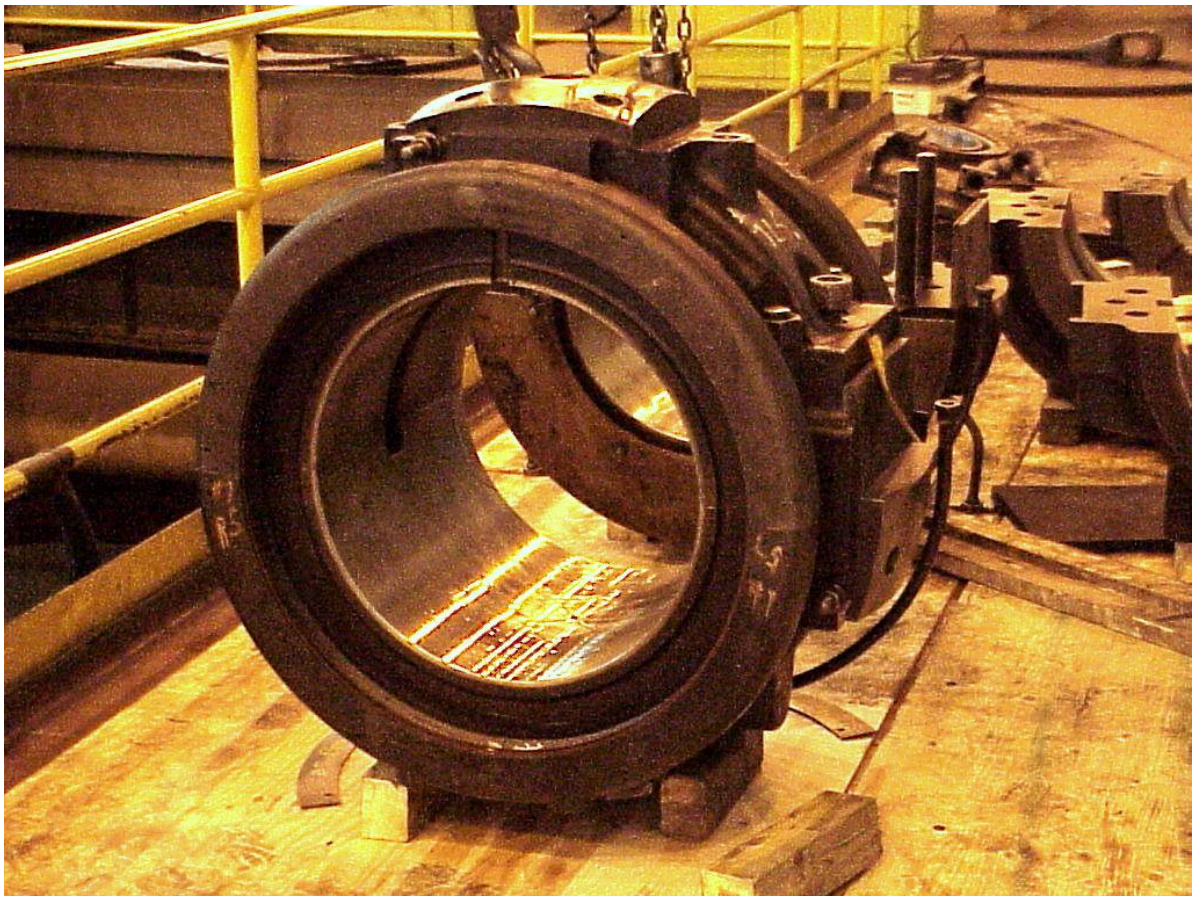


Figure 516. Large turbine bearing. Notice the oil groove on left hand side and the spherical seat at the very top.

### 10. How long are turbine bearings in relation to shaft diameter?

Turbine bearings are about 0.8 to 1.3 times as long as the diameter.

*S&V page 78.*

### 11. What is the safe load limit on a turbine bearing journal?

A unit bearing pressure of about 200 psi is the upper limit at present.

*S&V page 78*

## 12. In a properly fitted bearing, how much of the journal touches the shaft?

None, the oil film is 1/1000 to 2/1000 per inch of journal diameter. The proper amount of clearance between a journal and its bearing is about 0.001 inch for each inch of shaft diameter.

*Croft Steam Engine Principles and Practice, 1st Edition, page 402.*

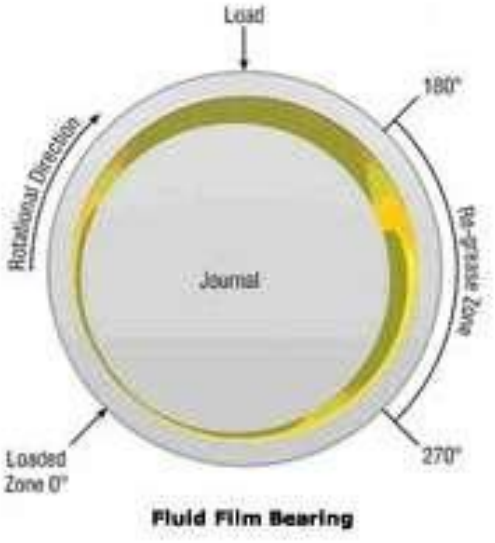



Figure 517. Full oil film

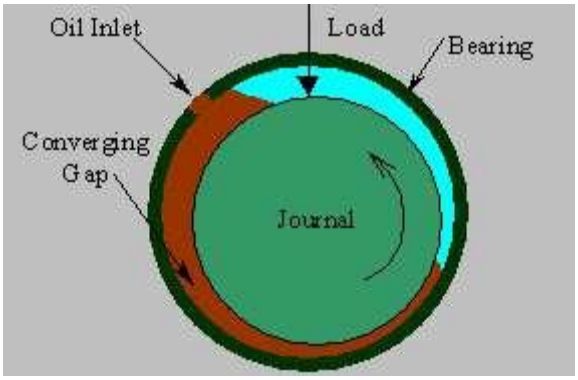



Figure 518. The shaft or journal of the rotor floats on oil. There should never be metal to metal contact

## 13. What type bearings are used on a turbine?

There are two (3) types of bearing used on larger turbines.

1. Plain Journal Bearings

2. Tilting Pad Journal Bearings

3. Thrust Bearings

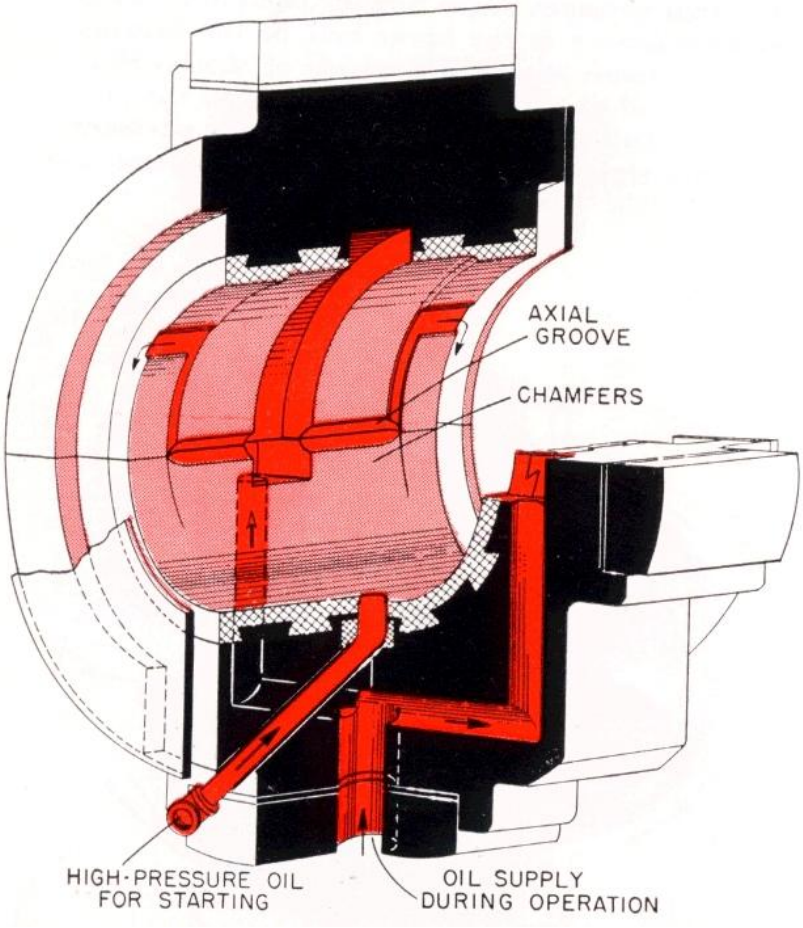


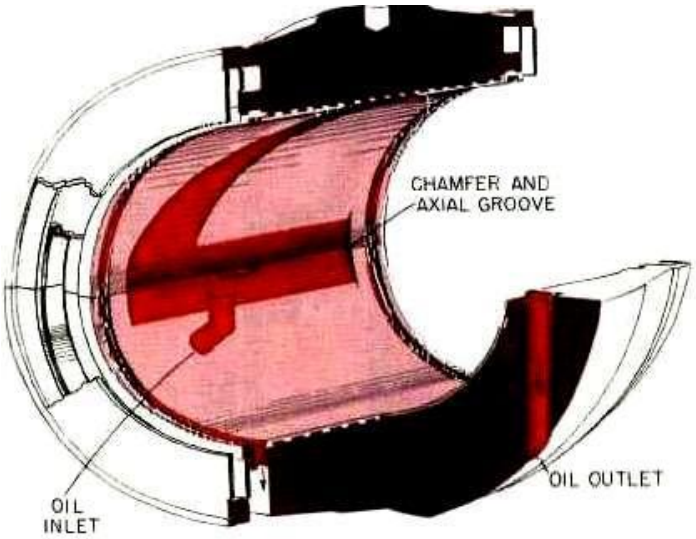

Figure 519. Chamfers and grooves for distributing oil. Allis Chalmers bearings have high pressure oil from bottom hole on startup. Then oil flows from annular groove in bearing cap to relieved portion of upper bearing to form the oil wedge so the bearing is supported.

## 14. Why are grooves put in bearings?

Grooves are put in bearings to distribute oil along the length of the journal.

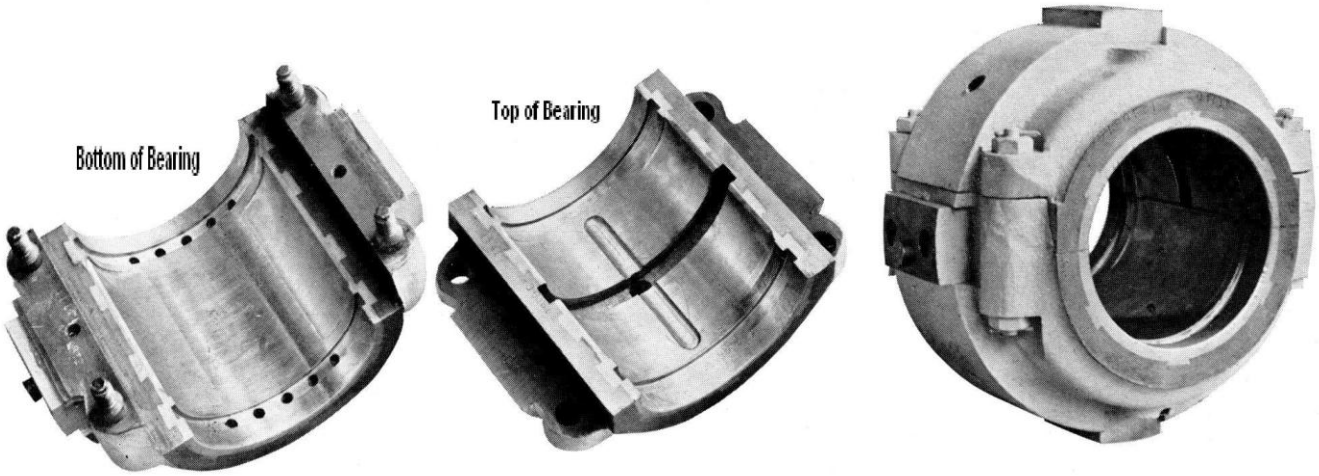
## 15. Explain how and where grooves are cut into the bearings.

The grooves are made with chamfered or round edges, in the direction of rotation, so as not to scrape off oil. The grooves extend within approximately to 1/2 inch of bearing ends. These grooves are never cut in the high pressure area of oil wedge but are placed parallel to the shaft in the low pressure area.




**Split journal bearing with a wide diagonal and axial groove with chamfer to permit a large oil flow for cooling purposes.**

Figure 520.




BEARINGS OF 3000 KW BLEEDER TURBINE. FLOOD LUBRICATED UNDER FIVE POUND OIL PRESSURE.
Courtesy Westinghouse Electric & Mfg. Co.

Figure 521.

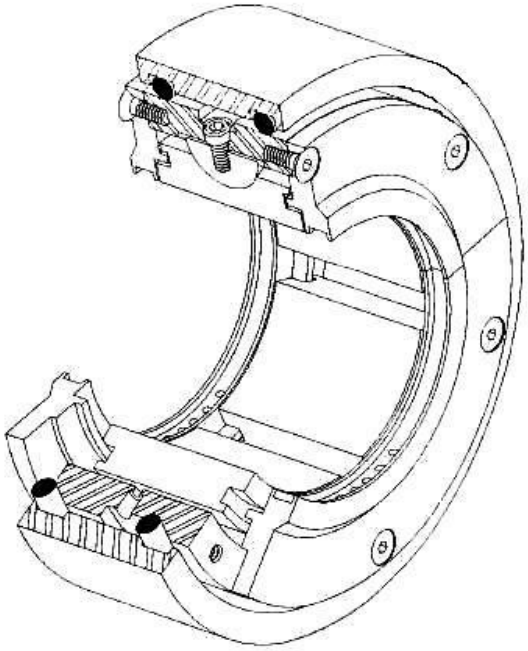
Figure 522. Cutting the oil grooves into the babbitt. The grooves are normally in the upper bearing while the lower bearing is left plain because it has to support all the weight.

Figure 523. Large turbine bearing; showing the chamfer in the side and the horizontal groove for oil to enter the bearing.

Figure 524. Tilting pad bearing inside the shell

Figure 525. An assembled tilting pad bearing and one in two pieces showing the construction

Figure 526. The half-moon buttons fit into recesses between the pad and the shell and allows movement of the pad to follow the turbine shaft



*Isometric View of Complete Four-Pad Tilting Pad and Squeeze Film Damper Bearing.*

Figure 527.

## 16. Explain Tilting Pad Bearings.

These are bearings with semicircular pads inside the bearing shell. These pads rock on half-moon shaped steel buttons that allow flexible movement of the pad while providing support for the turbine rotor.

## 17. Why do bearings become hot?

Bearings become hot from friction and heat which flows through the shaft from high temperature parts.

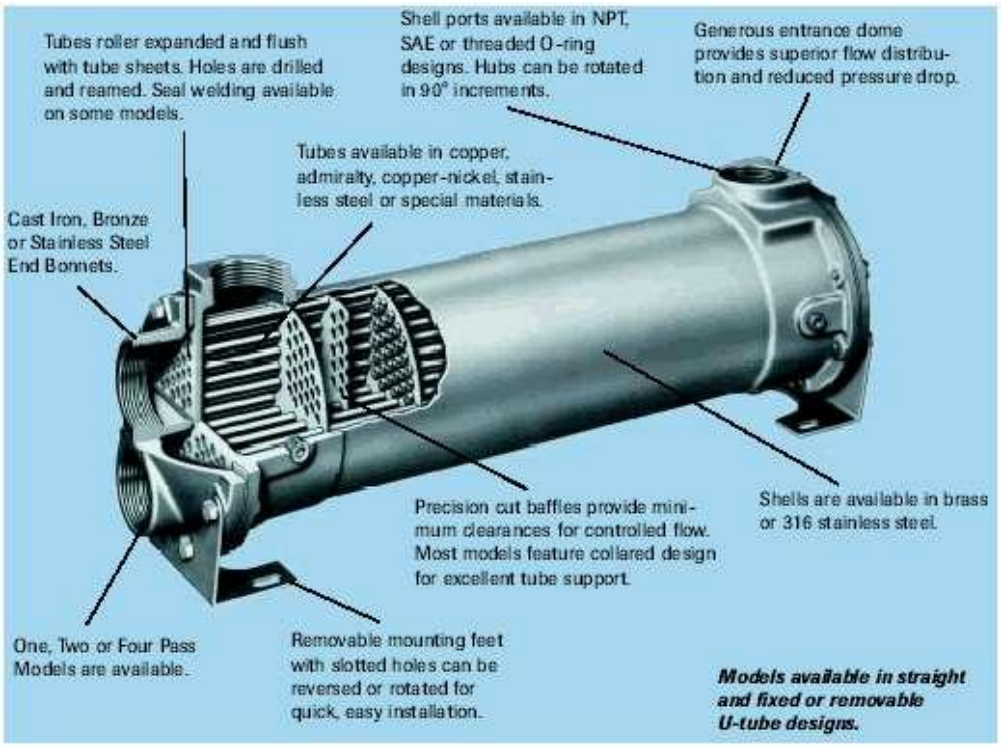

Tubes roller expanded and flush with tube sheets. Holes are drilled and reamed. Seal welding available on some models.
Shell ports available in NPT, SAE or threaded O-ring designs. Hubs can be rotated in 90° increments.
Generous entrance dome provides superior flow distribution and reduced pressure drop.
Tubes available in copper, admiralty, copper-nickel, stainless steel or special materials.
Cast Iron, Bronze or Stainless Steel End Bonnets.
Precision cut baffles provide minimum clearances for controlled flow. Most models feature collared design for excellent tube support.
Shells are available in brass or 316 stainless steel.
One, Two or Four Pass Models are available.
Removable mounting feet with slotted holes can be reversed or rotated for quick, easy installation.
Models available in straight and fixed or removable U-tube designs.

Figure 528. Straight tube oil cooler

## 18. How is the oil cooled?

Oil is cooled by use of oil coolers.

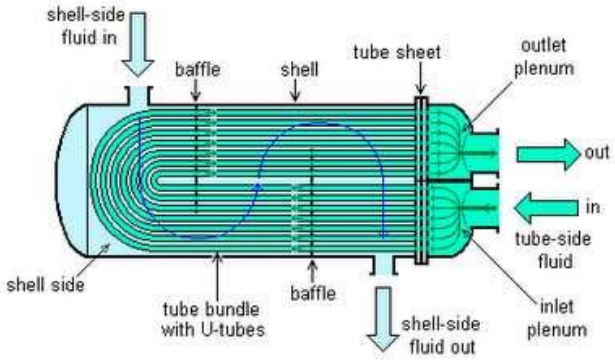



Figure 529. U-tube oil cooler

Shell and tube heat exchanger design

## 19. What should the supply temperature of oil be for large turbines?

Oil supply temperature of large turbines is about 110 to 120 F.

## 20. How much should oil temperature rise through the bearing?

20 to 30 degrees F. Oil from the bearings should be no hotter than 150 degrees

*S&V page 65, D.E.S.C. Lubrication Section, Kents 11th page 8-42*

## 21. What are the factors that contribute to bearing failure in a steam turbine?

Improper lubrication. Only the recommended lubricant should be used.

Inadequate water-cooling. The jacket temperature should be maintained in the range of 120 to 140 degrees Fahrenheit.

The flow of cooling water should be adjusted accordingly.

Misalignment.

It is desirable that ball bearings should fit on the turbine shaft with a light press fit. If the fitting is too tight, it will cause cramping. On the other hand, if the fitting is too loose it will cause the inner race to turn on the shaft. Both conditions are undesirable. They result in wear, excessive vibration and overheating. And bearing failure becomes the ultimate result.

Bearing fit.

Excessive thrust.

Unbalance.

Rusting of bearing.

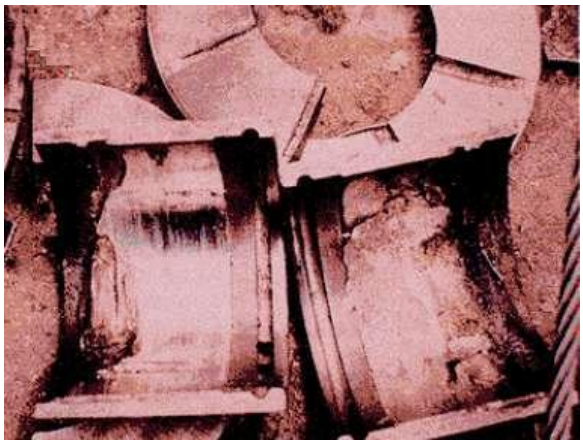
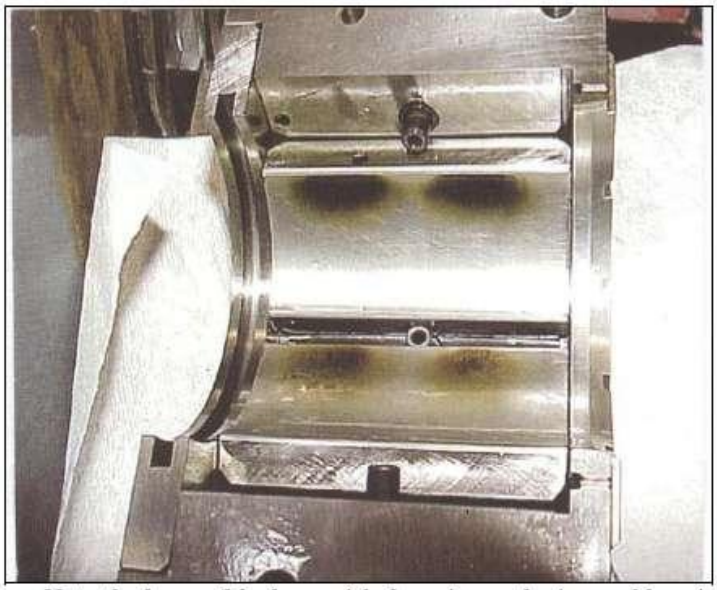


Figure 530. Bearing destroyed by overheating and lack of oil



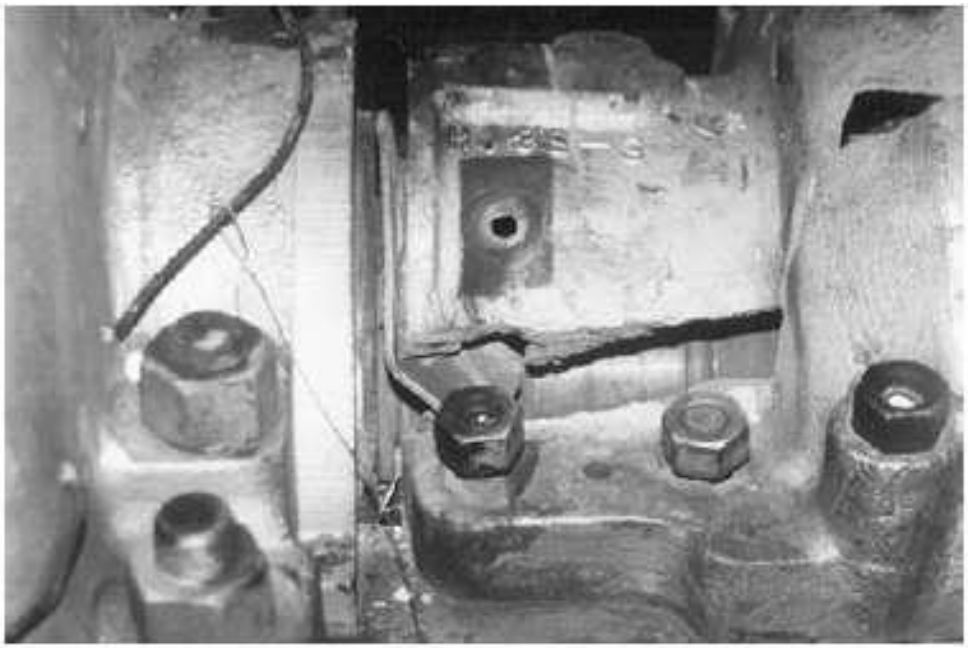
. **Note the brown/black varnish deposits on the journal bearing. These deposits "may" have formed at these bearing areas because these particular areas experienced the highest temperatures and/or the lowest oil flow.**

Figure 531.

Figure 532. Dirty oil led to this bearing failure

Figure 533. Steam turbine bearing failure

Figure 534. Brass bearing showing wiping from inadequate lubrication



*Turbine Inboard Bearing Cap Split.*

Figure 535. Bearing overheating caused the cap to split.

Figure 536. Lack of oil caused overheating

Figure 537. Lack of oil leads to melting of the babbitt

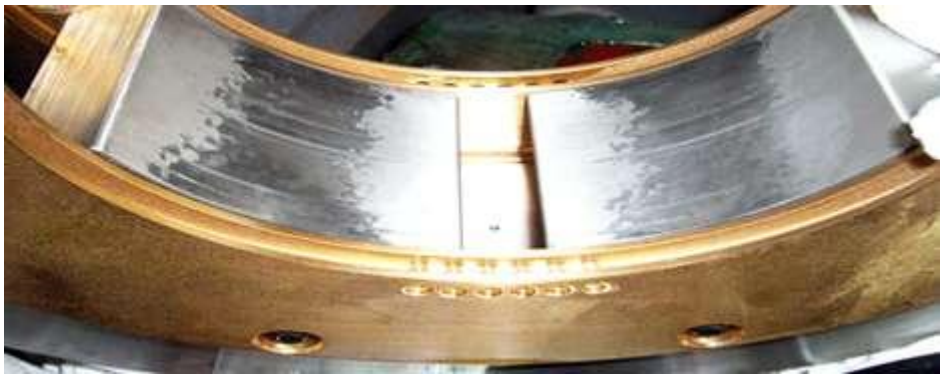


Figure 538. Tilting pad journal bearing wiping from lack of lubrication

# Chapter 13 Thrust Bearings

## 1. What are thrust bearings?

A thrust bearing is one which takes care of the forces acting along the shaft axis. There are several types

## 2. What is the function of a thrust bearing?

Thrust bearings keep the rotor in its correct axial position.

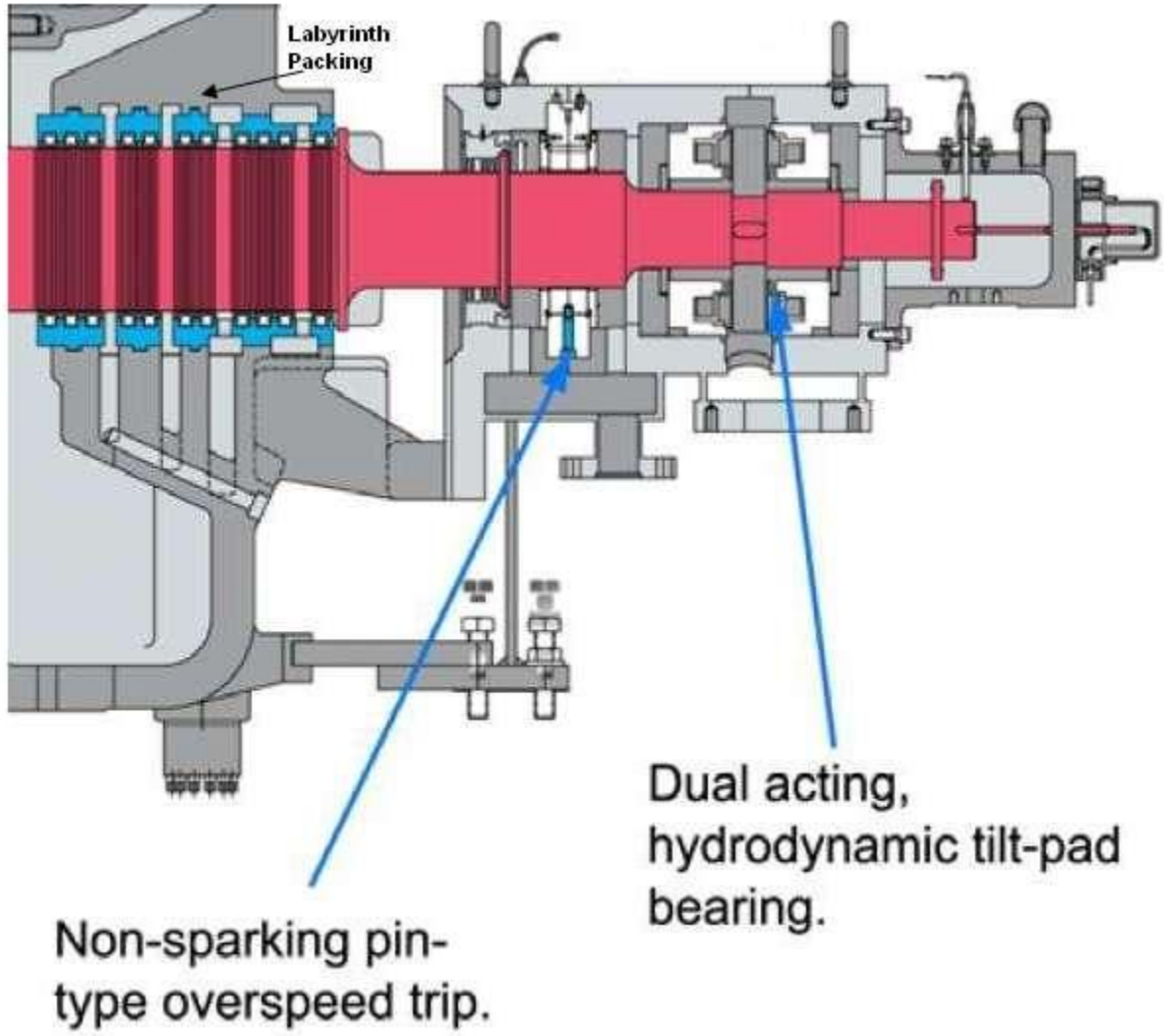



Figure 539. The thrust bearing is the dual acting hydrodynamic tilt pad bearing. The rotor is to the left and the rotor will expand to the left while the casing will expand to the right.

## 3. What are four types of thrust hearings?

1. Babbitt-faced collar bearings.

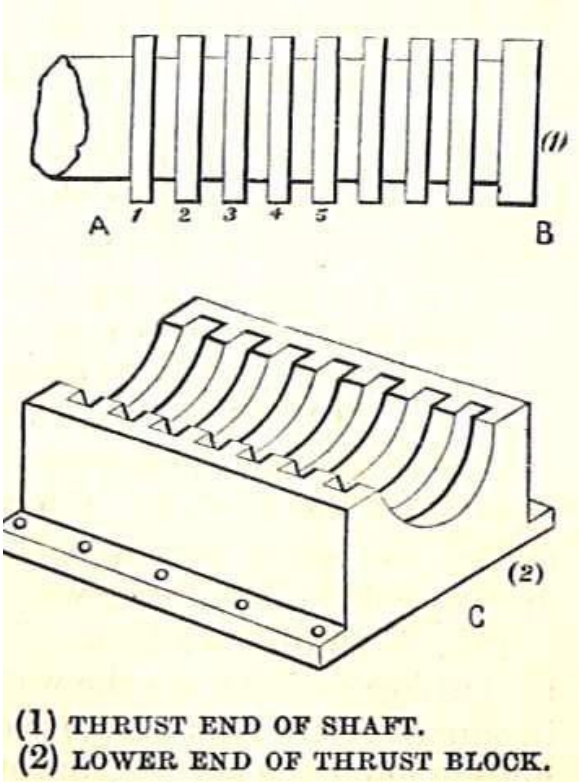



Figure 540. Babbitt-faced collar bearings

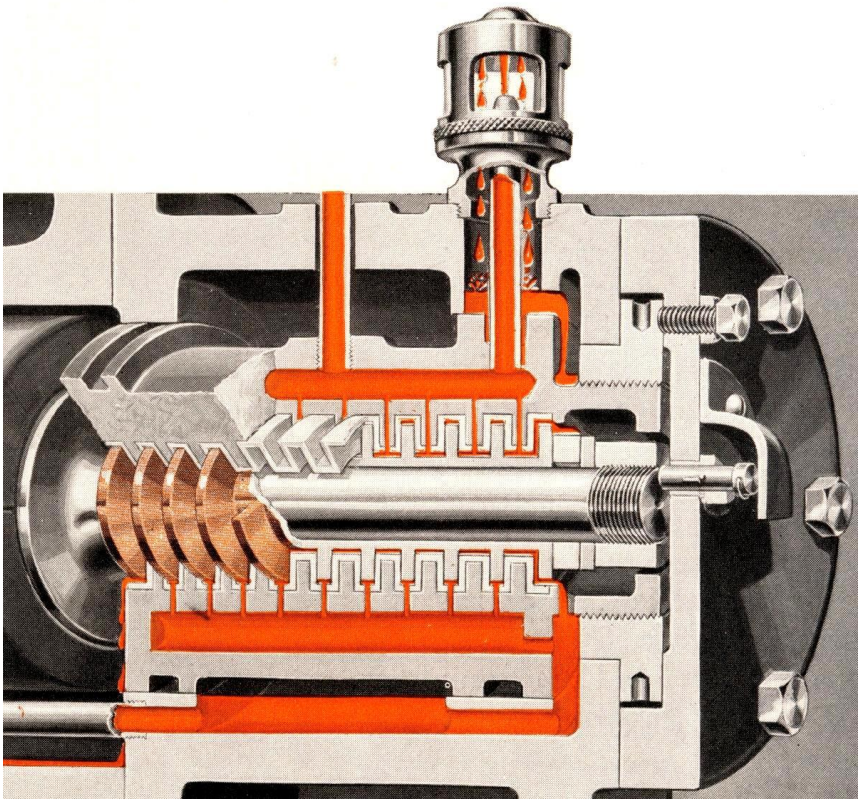


Figure 541. Babbitt-faced collar bearings showing the oil feed to the thrust bearing

2. Tilting pivotal pads. (Kingsbury Thrust Bearings)

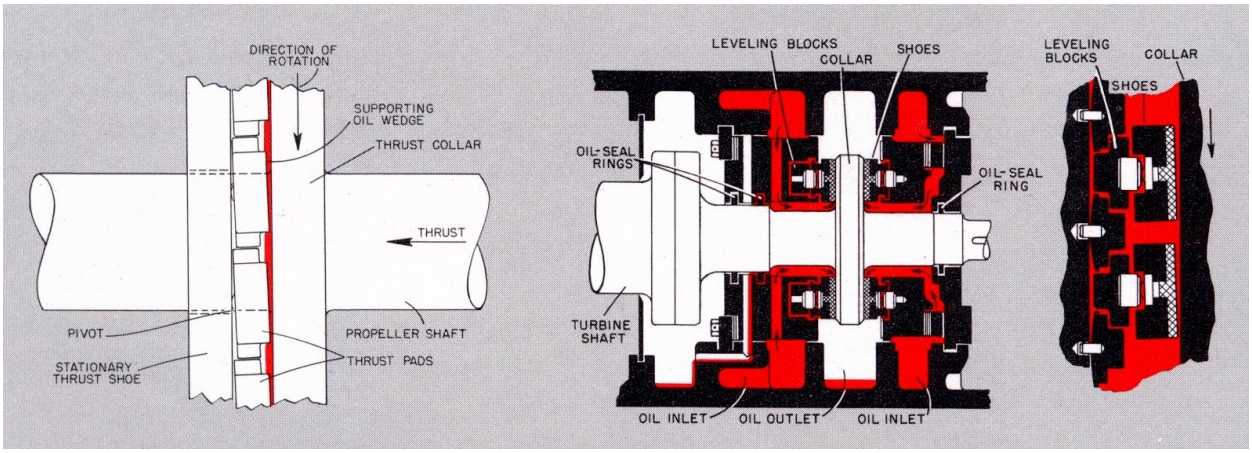



Figure 542. Kingsbury thrust bearing showing the oil wedge created when the pads rock into position

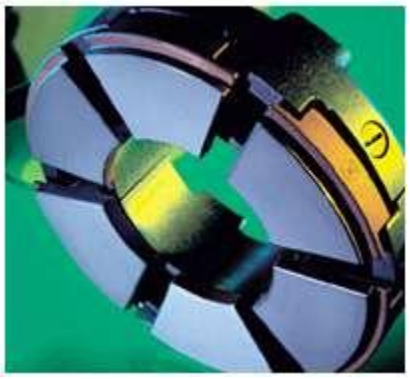


Figure 543. Assembled Kingsbury thrust bearing

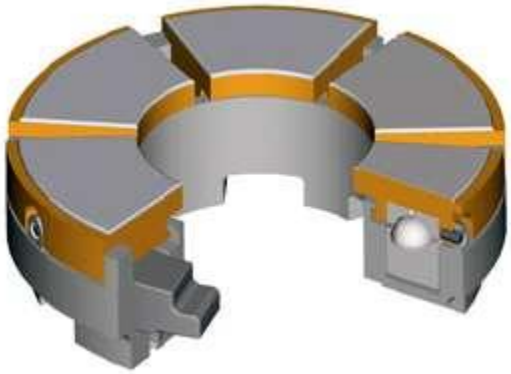


Figure 544. Cutaway of Kingsbury thrust bearing

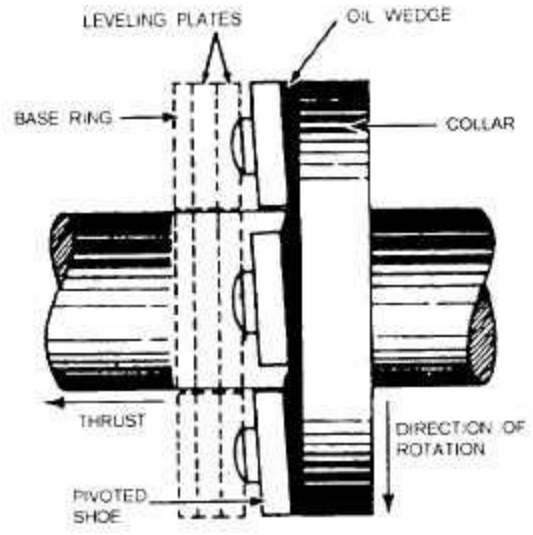



Figure 545. Oil wedge created by rotating tilting pads

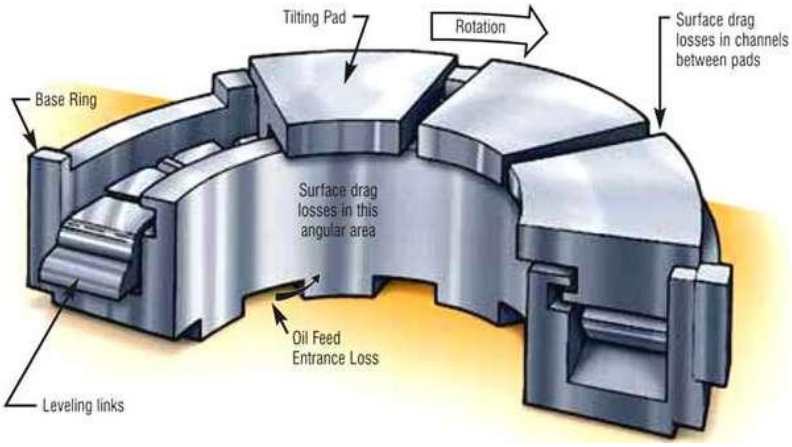



Figure 546. Cutaway of Kingsbury thrust bearing

3. Tapered land bearings.

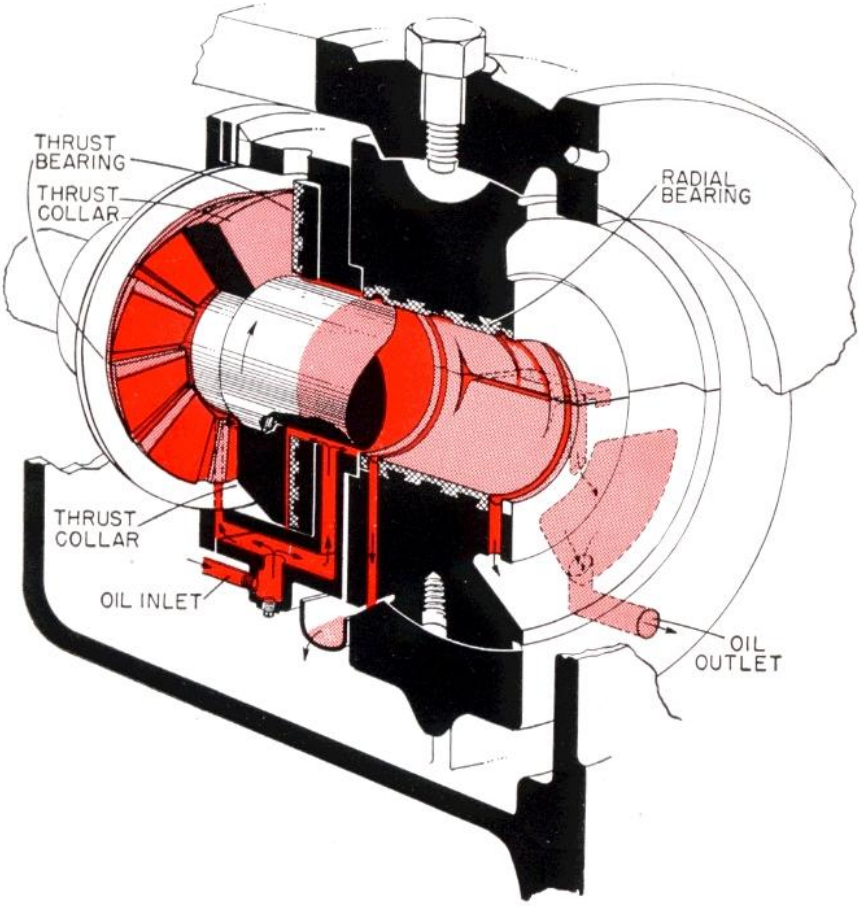



Figure 547. Tapered Land Thrust Bearing .Rotation of the collar draws oil from the radial grooves into the wedges formed by the beveled section on each sector forming a full film oil wedge

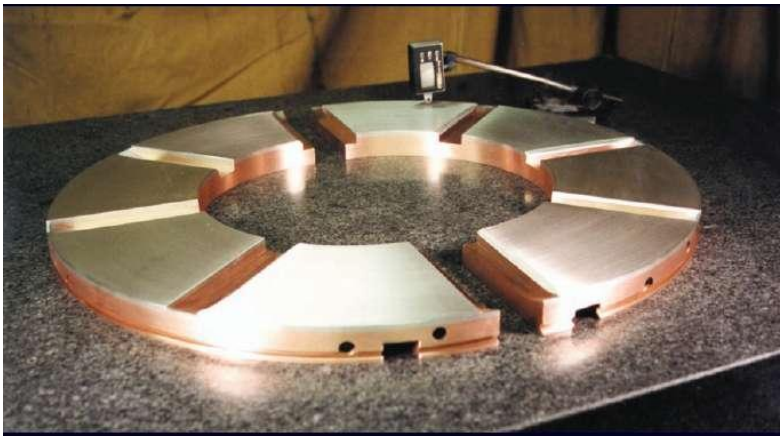


Figure 548. Showing the construction of the tapered land thrust bearing and its split into two halves for assembly and disassembly. Notice the taper of the pads

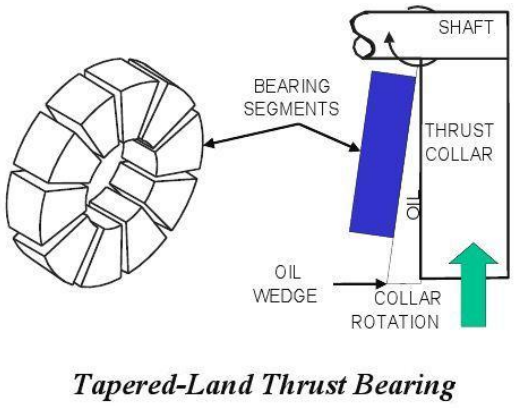



Figure 549. Tapered land thrust bearing oil wedge explained

4. Rolling-contact (roller or ball) bearings.

Figure 550. Tapered roller bearings

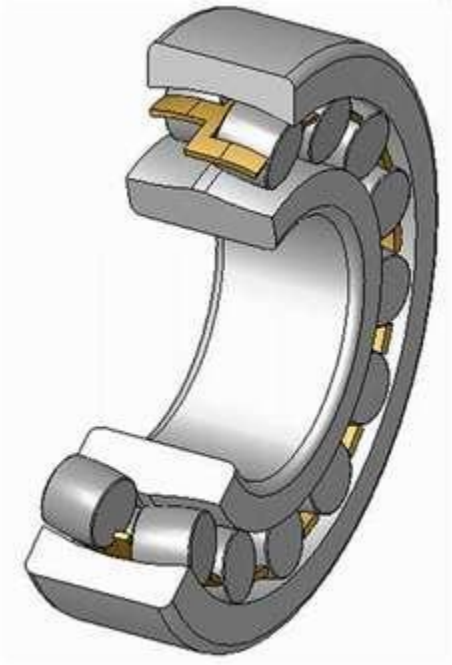


Figure 551. Double roller bearings

Figure 552. Double ball bearings

## 4. Explain a thrust bearing for a large turbine.

The thrust bearing is a device used to support the axial thrust of the rotor. It consists of a rotating collar rigidly attached between two bearing surfaces or shoes.

Two (2) main types are:

1. **Tapered Land** - In operation the thrust collar and the bearing surfaces are separated by a wedge of oil. The entire bearing assembly operates in a bath of oil. The bearing faces are divided off by oil grooves into segments called lands. These lands are not flat but are tapered on one side. This taper permits the entrance of oil and wedge of oil to be formed. The bearing is pressure lubricated.

The babbitt face of a tapered-land thrust bearing has a series of fixed pads divided by radial slots. The leading edge of each sector is tapered, allowing an oil wedge to build up and carry the thrust between the collar and pad.

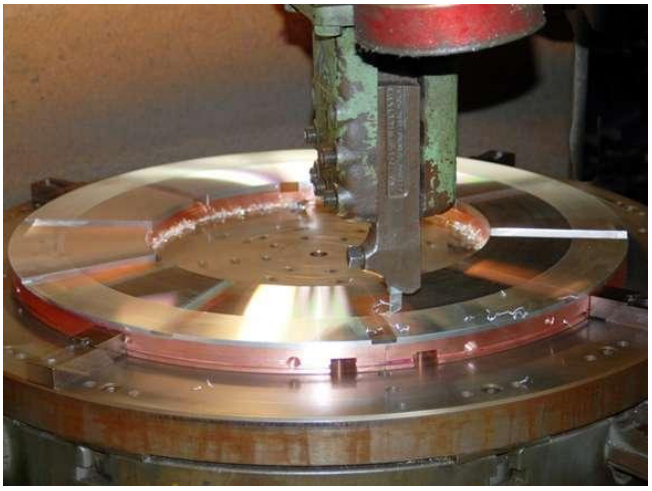
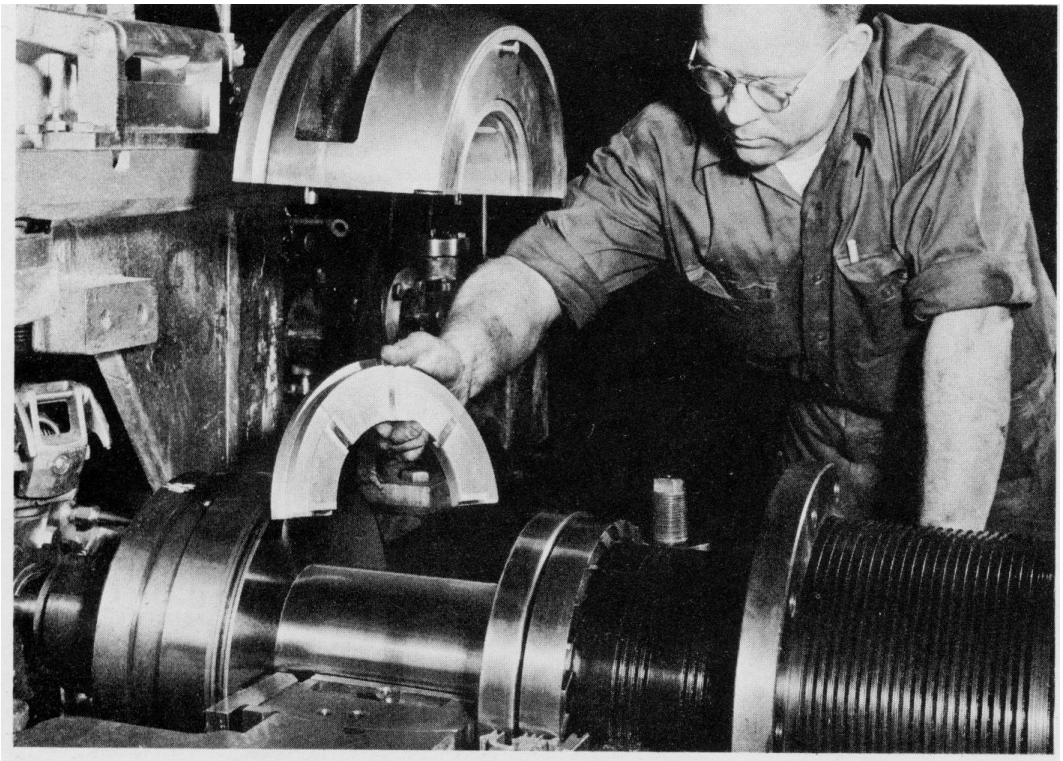


Figure 553. Machining a tapered land bearing



Dovetails are machined into the backing of the thrust bearings to provide a mechanical connection between the babbitt and steel.

Figure 554. Installing a tapered land bearing

Figure 555. Albert Kingsbury

Figure 556. Assembling a Kingsbury thrust bearing

The tilting pad thrust bearing was first conceived and tested by Albert Kingsbury more than 100 years ago and eventually revolutionized thrust bearing design. It allowed a more than tenfold increase over existing design unit loads, with a simultaneous reduction in frictional forces of the same or greater magnitude. It is a design concept of elegant simplicity which has remained essentially unchanged since its introduction. It has been applied to perhaps hundreds of thousands of rotating machines with unparalleled success – to ship propeller shafts, steam and gas turbines, hydro-generators, pumps, compressors, etc. The use of this bearing has added immeasurably to the life, reliability and economic performance of such machines now for scores of years. *Jim McHugh, Consultant, Tucson, Arizona*

2. **Kingsbury Thrust Bearing** - This bearing consists of a rotating thrust plate and a series of pivoted shoes fastened to a stationary ring. The whole assembly is housed to run in an oil bath. The rotating collars carry oil to the shoe bearing surfaces and a wedge of oil is formed between the shoes and collar. This bearing is supplied with oil under pressure. The Kingsbury can carry 10 times the load as a standard bearing. Load carrying capacity is 250 to 425 PSI of bearing area.

*D.E.S.C. Lubrication Section page 34*

The Kingsbury thrust bearing has its total surface divided into a number of segments. These are free to rock and take a position set by the formation of an oil wedge between them and the rotating collar. The thrust load distributes evenly among the segments. Axial adjustment of the bearing and, therefore, of the rotor can be made. Oil under pressure circulates to all moving parts. Thrust collar commonly mounted at the high pressure end of the turbine.

An effective oil wedge is formed because of either tilting pads or beveled surfaces on the stationary part. This oil wedge can support heavy loads.

## 5. Does the Kingsbury thrust bearing account for radial or axial thrust?

The Kingsbury thrust bearing is used when a large thrust load must be carried to maintain proper axial position in the turbine cylinder. The thrust shoes are made up of segments which are individually pivoted. With this arrangement, the pressure is distributed equally not only between the different segments but also upon the individual segments. The openings between the segments permit oil to enter the bearing surfaces. Almost 10 times as much pressure per square inch can be carried on the Kingsbury-type bearing as on ordinary thrust bearings. Axial position of the bearing and turbine rotor may be adjusted by liners, located at the retainer rings, on each end of the bearing. The bearing is lubricated by circulating oil to all its moving parts.

*Steam Plant Operation. Woodruff and Lammers, 5th Edition. page 451*

## 6. The design load on a Kingsbury thrust bearing should not exceed what psi range for safe operation.

The Kingsbury thrust bearing for steam turbines usually is designed to carry a load of 250 to 425 psi to allow for dirty or worn oil and to provide a wide margin of safety. Under ideal conditions it could carry 3000 psi. In the fixed type of thrust bearing, liners are placed between the thrust bearing cage and the pedestal to fix the spindle position in the turbine. The bearing sometimes is mounted in a cage which can be adjusted axially to properly locate the moving blades relative to the casing.

The mean speed on Kingsbury thrust blocks may be as high as 215 ft. per second; however, to keep the diameter small, lower speeds generally are used. Ample quantities of oil at low velocities must be supplied.

*Kents 11th Edition, page 8-39*

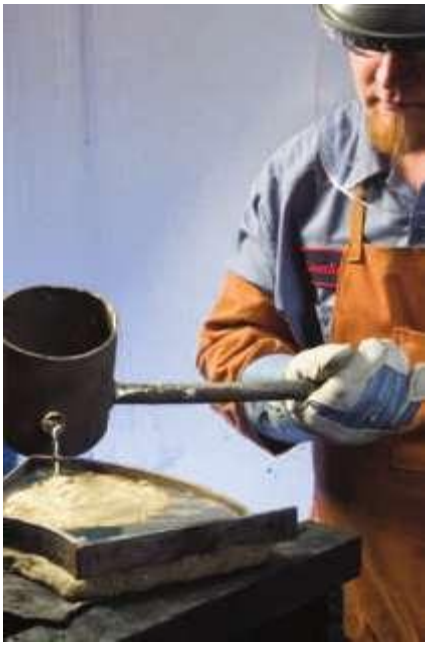


Figure 557. Pouring babbitt on a large tilting pad of a Kingsbury thrust bearing.

Figure 558. Scraping the babbitt surface of a large tilting pad of a Kingsbury thrust bearing.

**Stationary Pivoted Shoes**
The shoes in our thrust bearings (also known as pads or blocks) have three parts:

(1) body (normally carbon steel)
(2) shoe support (hardened steel with a spherical contact surface)
(3) babbitt face (high-tin babbitt which is metallurgically bonded to the body)

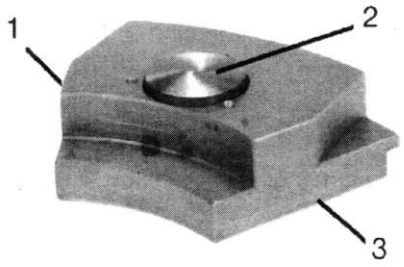



Figure 559. Parts of the tilting pad

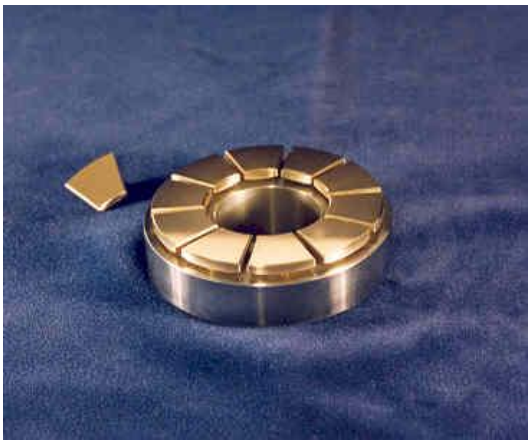


Figure 560. Small Kingsbury thrust bearing

## 7. What is a combination thrust and radial bearing?

This unit has the ends of the babbitt bearing extended radially over the end of the shell. Collars on the rotor face these thrust pads, and the journal is supported in the bearing between the thrust collars.

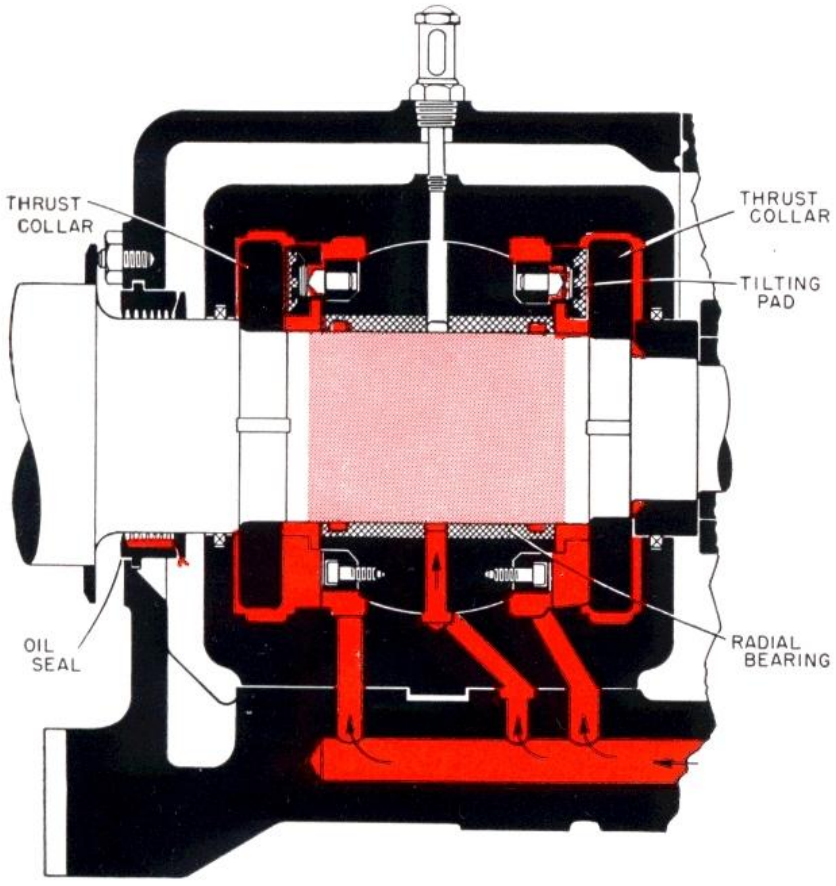



Figure 561. Worthington Combined thrust and radial bearing. The two thrust collars bear against tilting pads that are carried on the ends of the radial bearing

## 8. Where is the connection between the rotor and the casing?

This occurs at the thrust bearing. The thrust bearing is connected at the thrust collar of the rotor on one side and the casing on the other. The thrust collar is on the high pressure end of the rotor. As the rotor expands, it moves toward the low pressure end. The casing is connected rigidly at the condenser inlet on the low pressure end. While the rotor is heating up and moving toward the low pressure end, the casing is heating up and moving in the opposite direction toward the high pressure end. A 20 ft long turbine with a 900 degree inlet temperature and a 100 degree exhaust temperature will move 5/8 of an inch. This explains why the turbine must be warmed up slowly to account for this expansion.

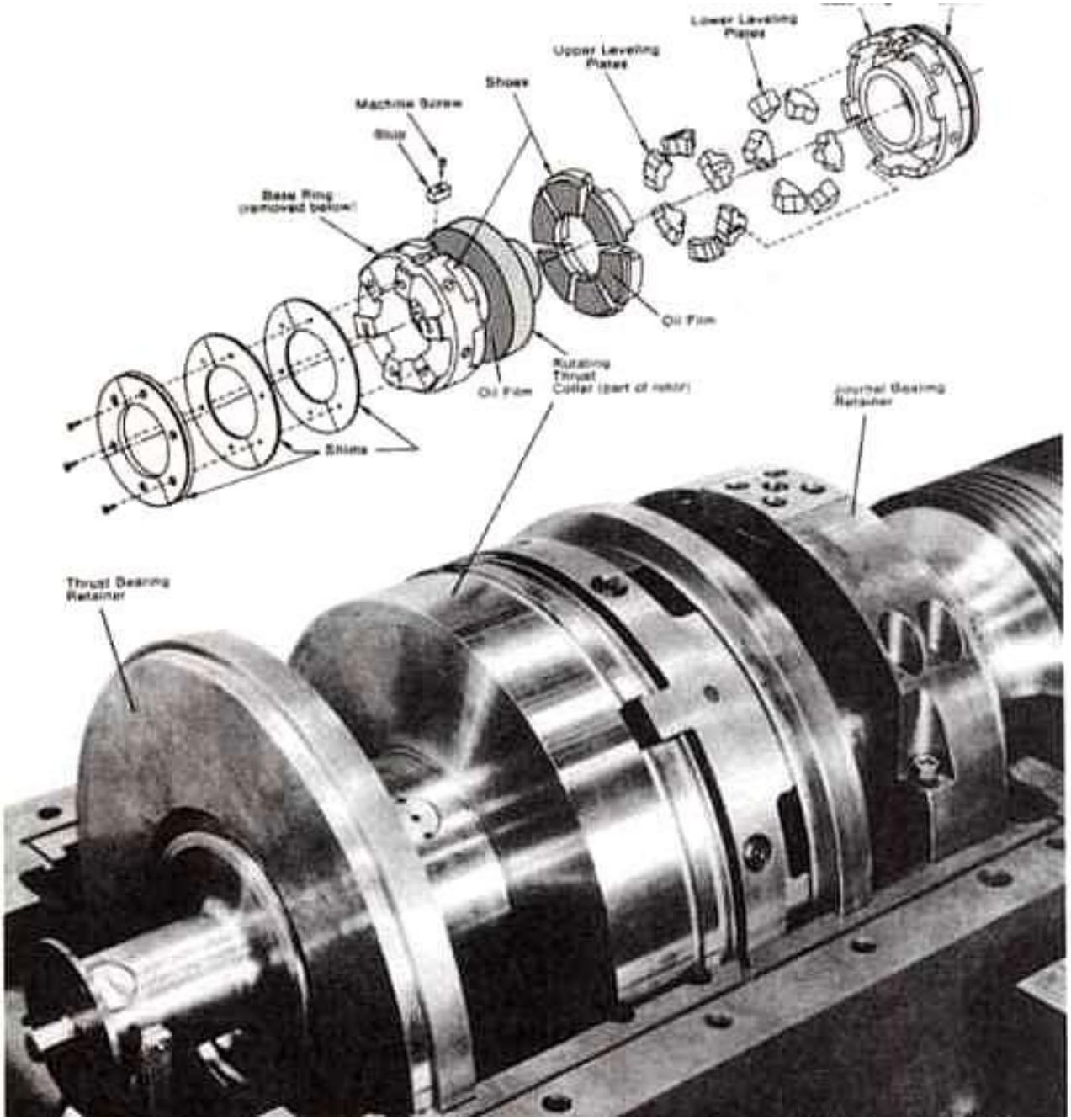



Figure 562. Shows the Kingsbury thrust collar which is part of the rotor. This is where the connection between the rotor and the casing is located.

# Chapter 14 Dummy Piston or Balance Piston

## 1. What is a balance piston?

Reaction turbines have axial thrust because pressure on the entering side is greater than pressure on the leaving side of each stage. To counteract this force, steam is admitted to a dummy (balance) piston chamber at the low-pressure end of the rotor. "Balance" or "dummy" pistons are rotating sections which counter balance the longitudinal thrust of the reaction rotor.

Some designers also use a balance piston on impulse turbines that have a high thrust.

Figure 563. The dummy piston is on the far right of the picture

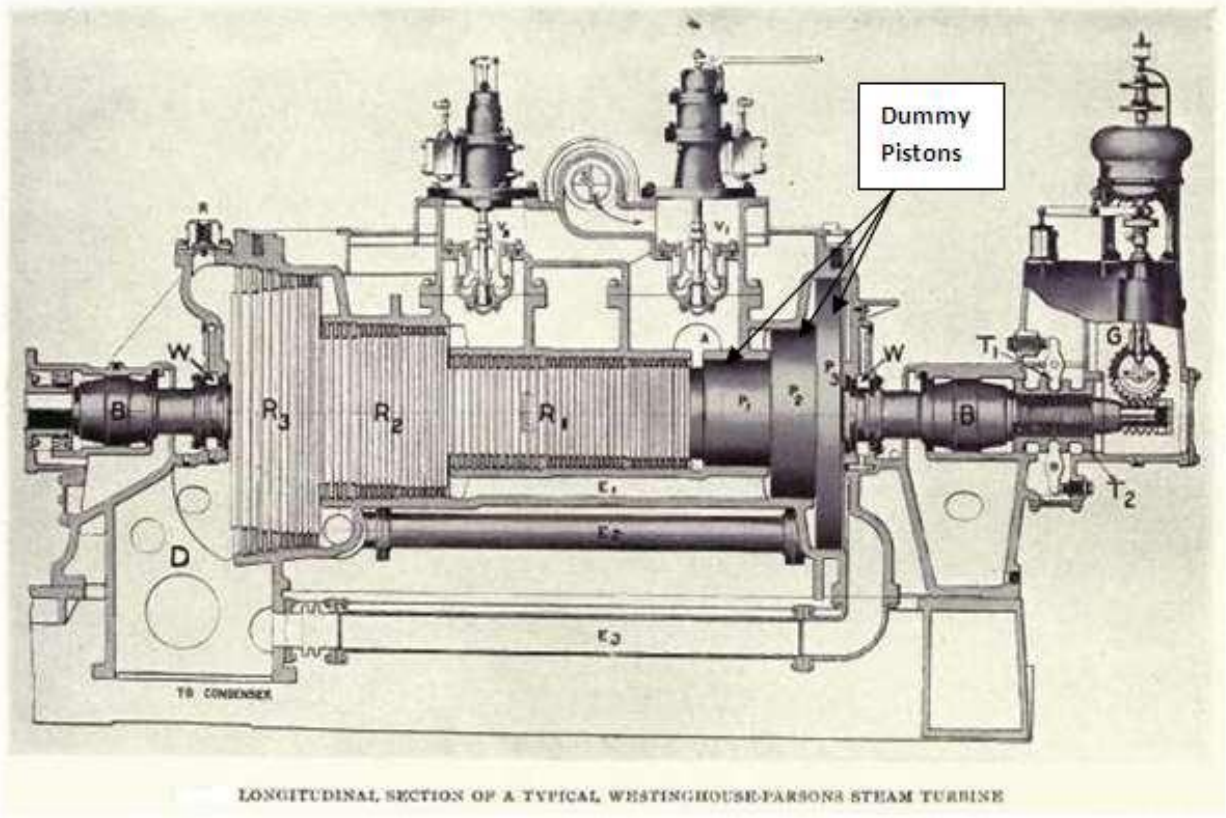



Figure 564.

## 2. Explain the balance piston (also known as the dummy piston).

The balance piston is part of the high pressure end of the turbine rotor and is used on reaction type turbines. Its a rotating section with a large amount of surface area to which suitable steam pressure can be applied to counteract the axial thrust on the rotor. Steam from turbine stages or the condenser can be piped to the face of the balance or dummy piston to obtain required pressures. Balance pistons use labyrinth gland to separate the high pressure on one side of the piston from the vacuum against the face of the piston. Although balance or dummy pistons work well to balance thrust, thrust bearings are always provided as well on all reaction turbines.

*Skrotzki & Vopat page 56*

*Edison Lubrication Section page 38*

*Kents 11th page 8-42*

*Higgins Turbines page 116*

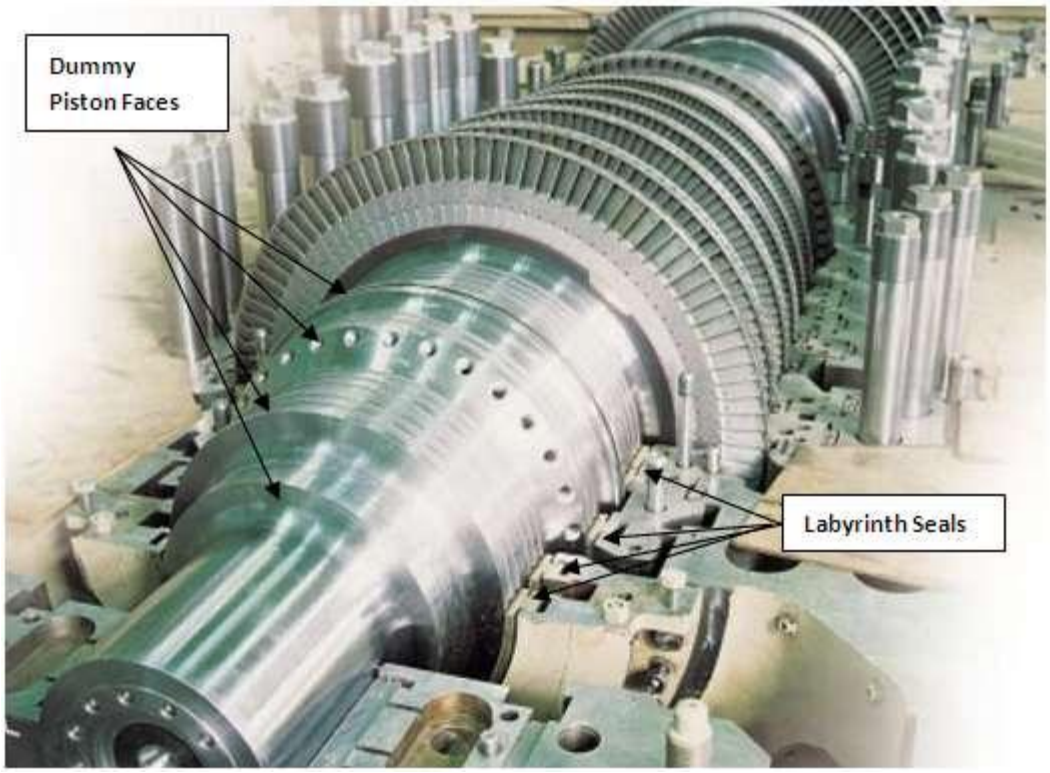



Figure 565.

## Which direction is the thrust of a turbine while in operation?

The thrust of the turbine rotor is toward the exhaust end due to the difference in pressure.

In order to counteract this thrust a balance piston is incorporated. Balance pistons are part of the high pressure turbine rotor with reaction blading. These balance pistons are rotating sections which counterbalance the longitudinal thrust of the reaction rotor. Higher steam pressures on the moving blade entering edges develop the rotor thrust. The balancing forces are brought about by allowing steam of suitable pressures to act on the balance-piston faces, and so to create a force in an axial direction. Steam from turbine stages or from the condenser may be piped to the balance-piston faces to obtain the required pressure or vacuum.

*S&V page 56*

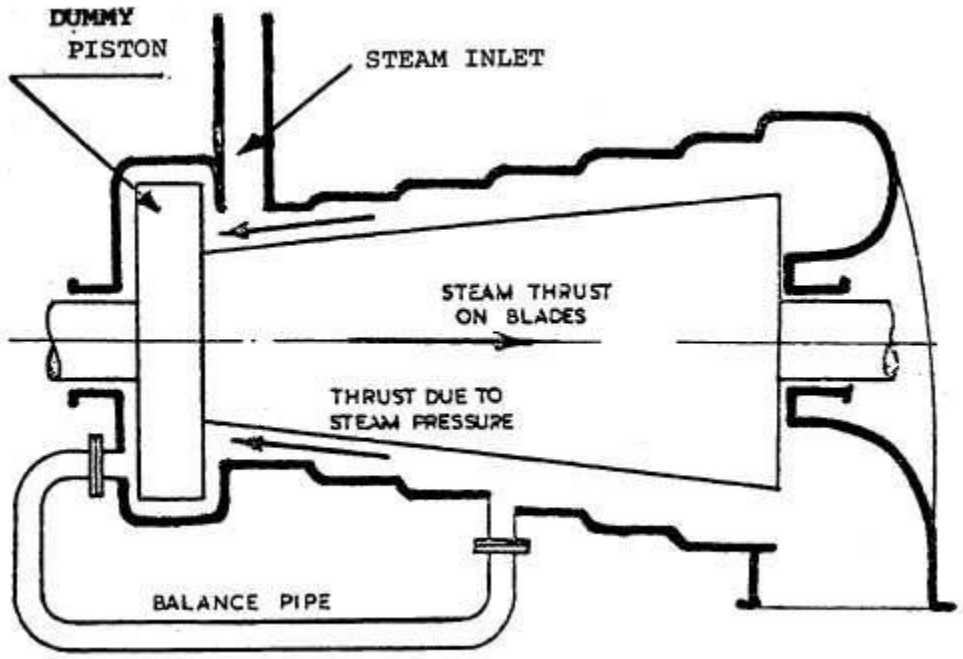



Figure 566. Balance pipe and dummy piston used to counteract thrust

Figure 567. Allis Chalmers rotor with dummy piston

Figure 568. Modern turbine rotor with dummy piston

# Chapter 15 Drains, Seals and Labyrinth Packing

## 1. Steam blowing from a turbine gland is wasteful. Why else should it be avoided?

It should be avoided because the steam usually blows into the bearing, destroying the lube oil in the main bearing. Steam blowing from a turbine gland also creates condensate, causing undue moisture in plant equipment.

Figure 569. Steam leaking from turbine shaft seal in a poorly maintained plant.

Figure 570. Steam leaking into a high voltage switchgear room is never a wise idea

Figure 571. Shaft seal steam leaks waste money and are dangerous to personnel

## 2. What is gland-sealing steam?

It is the low-pressure steam that is led to a sealing gland. The steam seals the gland, which may be either a carbon ring or labyrinth type against air at the vacuum end of the shaft. Steam sealing is used while starting the turbine. It positively stops air flow into the condenser at the exhaust-end gland and into the turbine at the high pressure end.

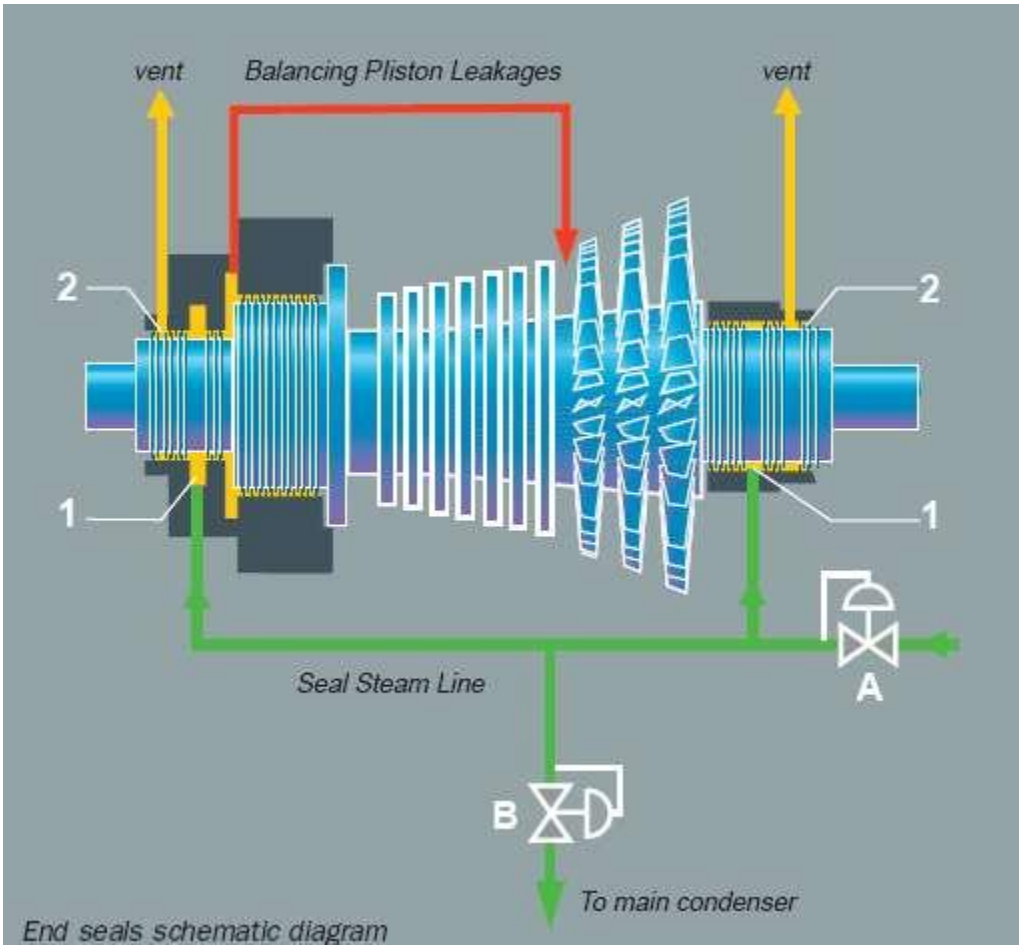



Figure 572. Steam seals prevent air infiltration on start-up

## 3. Where does the gland sealing steam go?

The steam condenses and drains to a feedwater heater

### 4. What is "leakoff steam"?

Leakoff steam is steam that leaks past the gland from a region of high pressure.

## 5. What is the function of a gland drain?

The function of a gland drain is to draw off water from sealing-gland cavities created by the condensation of the sealing steam. Drains are led to either the condenser air-ejector tube nest or the feedwater heaters. Often, gland drains are led to a low-pressure stage of the turbine to extract more work from the gland-sealing steam.

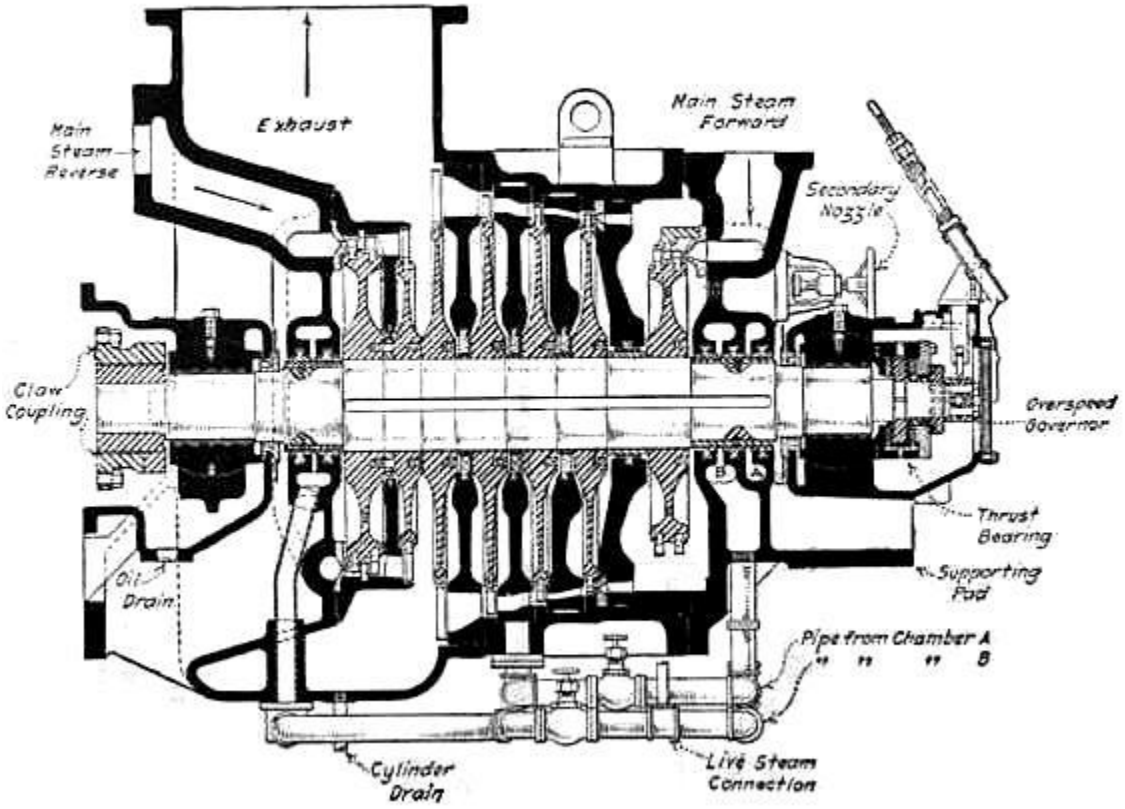



Figure 573. The cylinder drain is opened on startup to drain off condensate while the turbine is warming up

## 6. Why is it necessary to open casing drains and drains on the steam line going to the turbine when a turbine is to be started?

To avoid slugging nozzles and blades inside the turbine with condensate on start-up; this can break these components from impact. The blades were designed to handle steam, not water.

## 7. Why has damage due to moisture impingement been found even with moisture shields installed?

Moisture shields are designed and fabricated on the basis of predicted range of steam/water quantities impacting the blades at specific angles. Now if the operating conditions deviate significantly from design parameters then the erosion damage will occur. And in some cases it may go beyond nominal erosion wear and warrant repair. Also the corrosion of casing can occur due to blockage/clogging of water drains or extraction thereby forcing the water back into the casing. If this condensate water is carried over to steam path and impacts the blade, thermal-fatigue failure can occur within a short period.

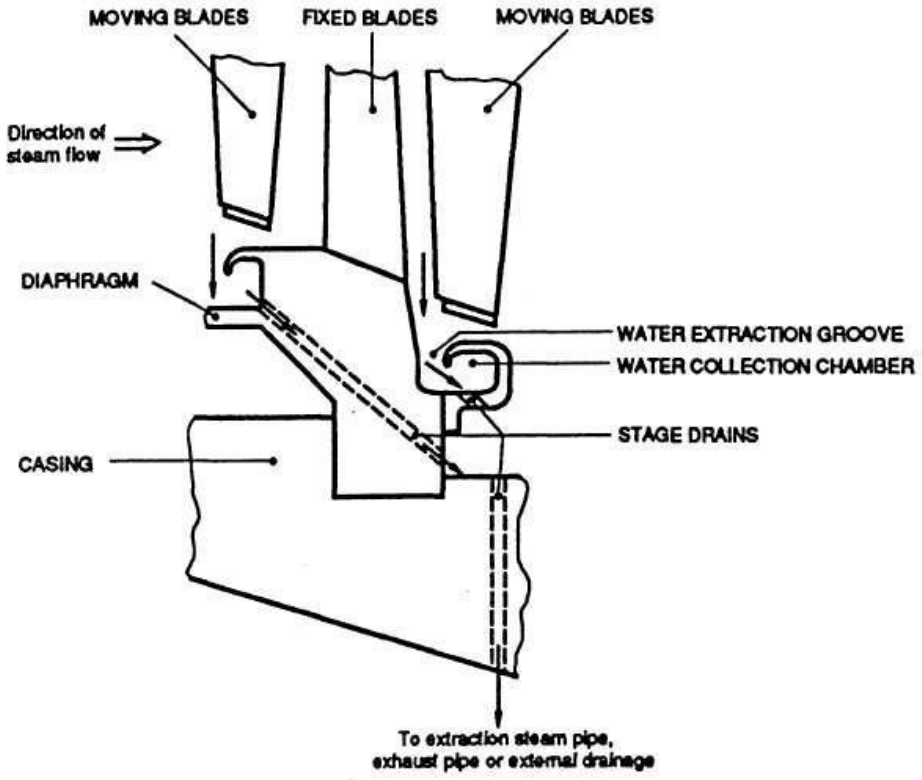
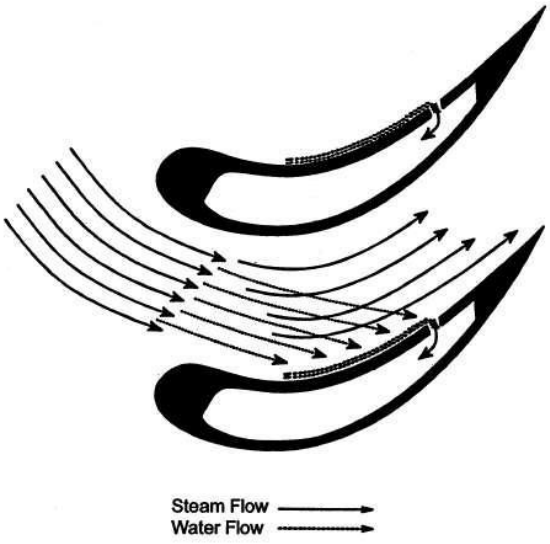



Figure 574. Some blades are designed to throw off moisture into water collection chambers to allow the water to be drained without damage to the turbine.




**Slotted moisture extracting fixed blade**

Figure 575.

Figure 576. Blade erosion

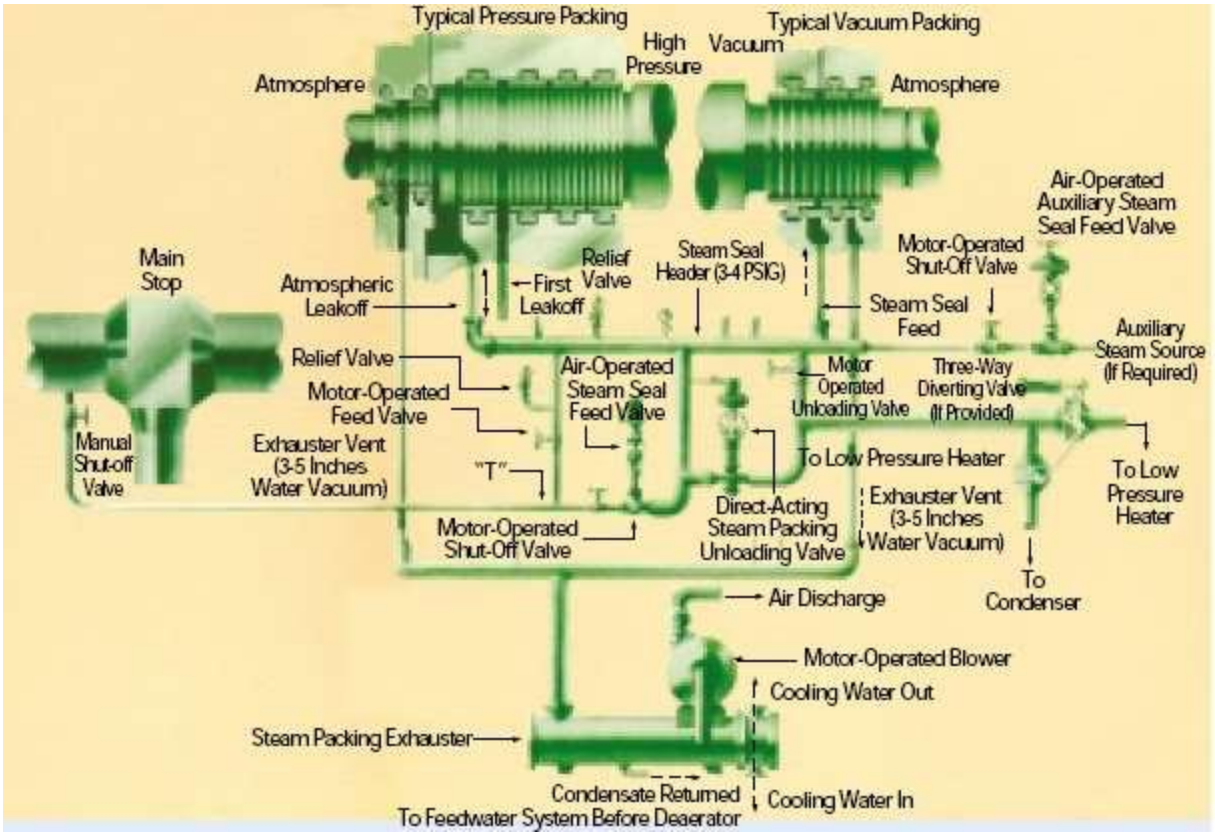
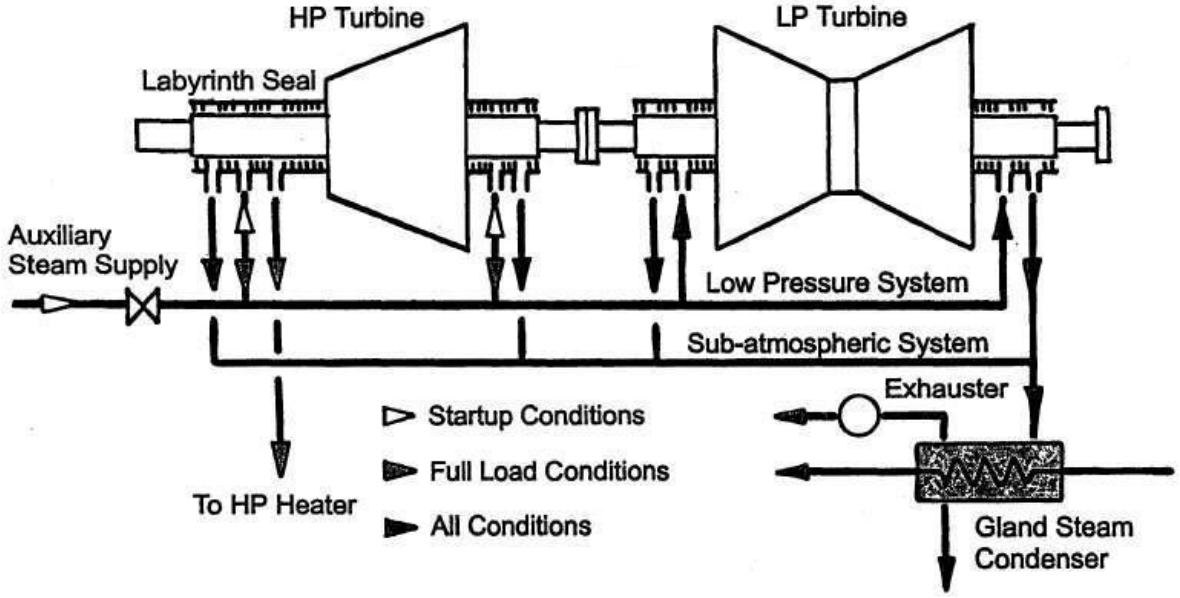



Figure 577. Sealing steam system use control valves and a gland seal condenser to return condensed seal steam to the feedwater system.




**Turbine steam sealing system**

Figure 578.

## 8. What are seven types of turbine seals?

**1.) Carbon ring packing** is a series of rings set with close shaft clearance. The ring consists of several arc segments of a circle held together around the shaft with garter or retaining springs.

Figure 579. Replacing the cover after changing the carbon ring packing. Notice the two oil rings on the turbine shaft.

Figure 580. Carbon ring with garter spring.

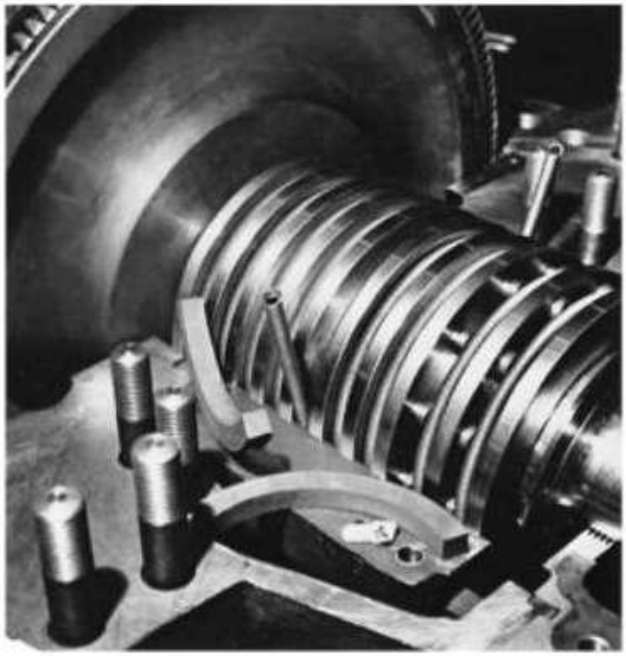


Figure 581. carbon ring grooves and two carbon ring pieces

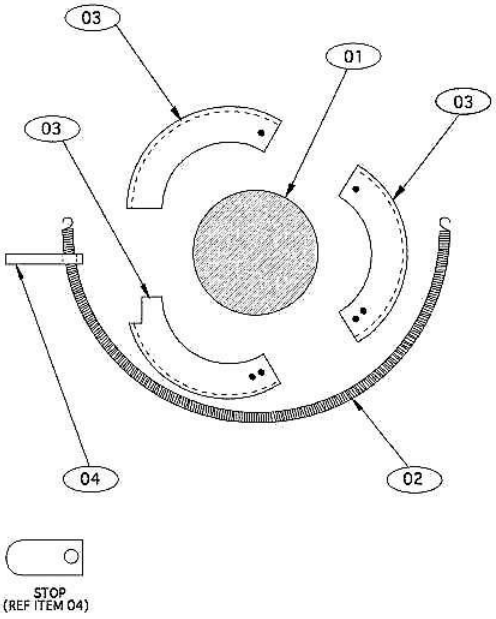



Figure 582. Parts of carbon ring packing. 01 is the turbine shaft. 02 is the garter spring that holds the carbon pieces together. 03 are the three carbon ring segments. 04 is the stop piece that keeps the carbon rings from turning with the shaft.

Carbon ring packing glands, are a series of close fitting carbon rings made in segments and held in their place around the shaft by garter springs. A stop piece in the housing prevents rotation of the ring. They do not turn with the shaft.

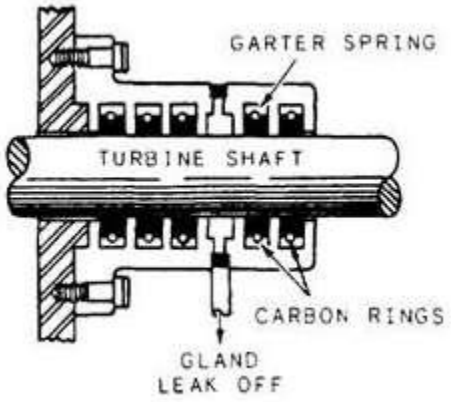



Figure 583. Carbon rings with a drain for condensate

This packing is enclosed by suitable holders in the turbine casing. Keys or lugs are provided in the holders which are self-lubricating and therefore require no oil. The segments of the two outside rings are made to overlap, thus allowing them to feed up to the shaft as wear occurs. Wear on the packing is taken up by springs which hold it in place around the shaft. The segments of the inner rings are made with squared ends and they just fit the shaft, or are a few thousandths of an inch loose. These rings exert no pressure on the shaft and no wear results. Steam is usually admitted to the spaces between the outer rings to prevent the entrance of air into the turbine when it is operating with a vacuum.

*"Engineering Bulletin No. T 36, page 17-18." S&V page 51*

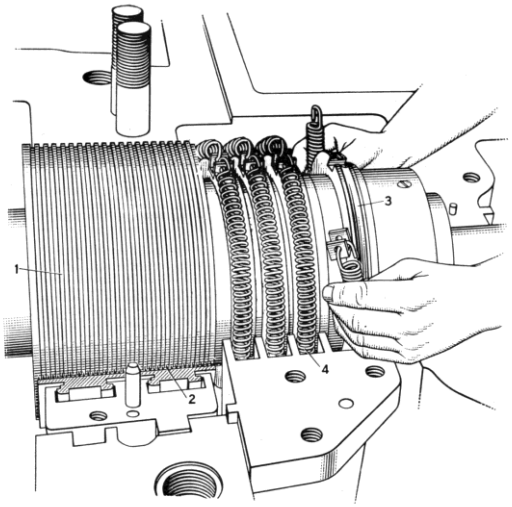



Figure 584. Installing the garter spring on the carbon segments

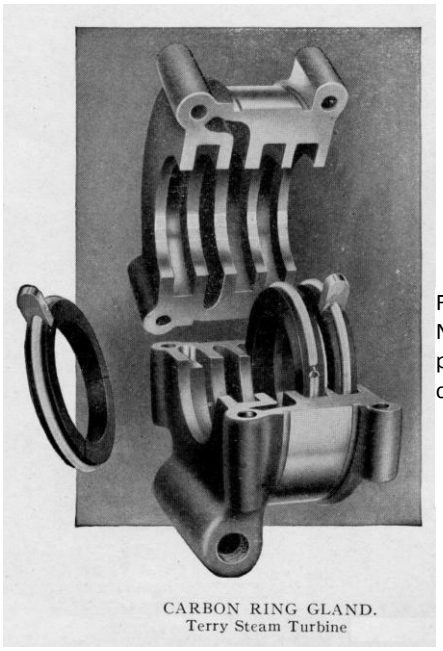



Figure 585. Notice the stop piece on the carbon ring

Carbon ring packing consists of circular segments held in place by garter springs. The packing ring does not rotate with the shaft. This type packing is used for both interstage and casing end packing. The rings work like piston rings sealing between the shaft and the ring housing. (Edison page 34)

Carbon rings have a throttling effect much like the labyrinth seal on any steam that leaks by.

*Edison Simple Turbine page 35*

## 9. What factors cause excessive steam leakage under carbon rings?

1.) Dirt under rings. - steam borne scale or dirt foul up the rings if steam is leaking under the carbon rings.

2.) scored or worn rotor

3.) worn or broken carbon rings. These should be replaced with a new set of carbon rings. The complete ring is replaced.

Figure 586. Small steam turbine with bad carbon ring packing

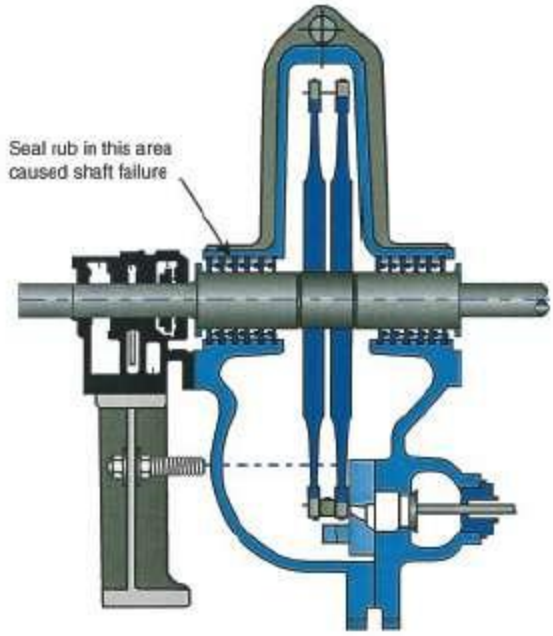



Figure 587. Carbon ring failure caused a shaft failure

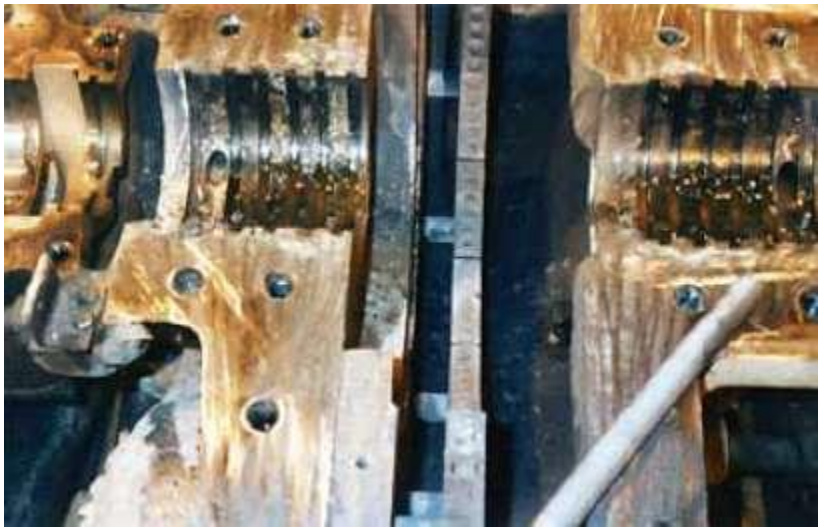


Figure 588. Carbon ring packing that was neglected too long before replacement

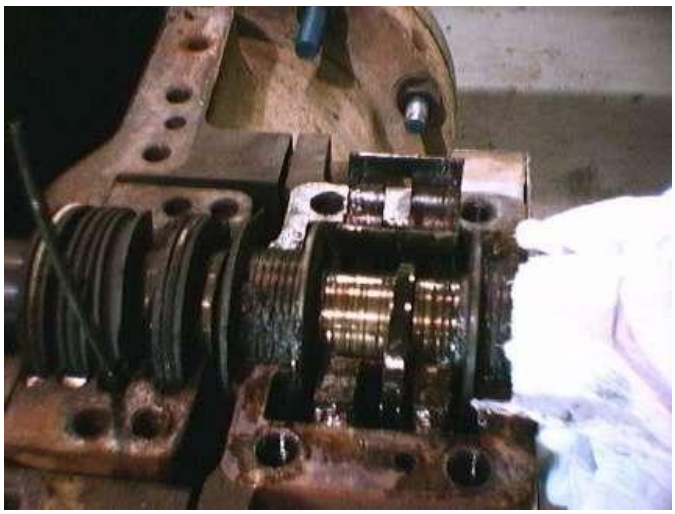


Figure 589. Carbon ring packing failure

Figure 590. Bad carbon ring packing

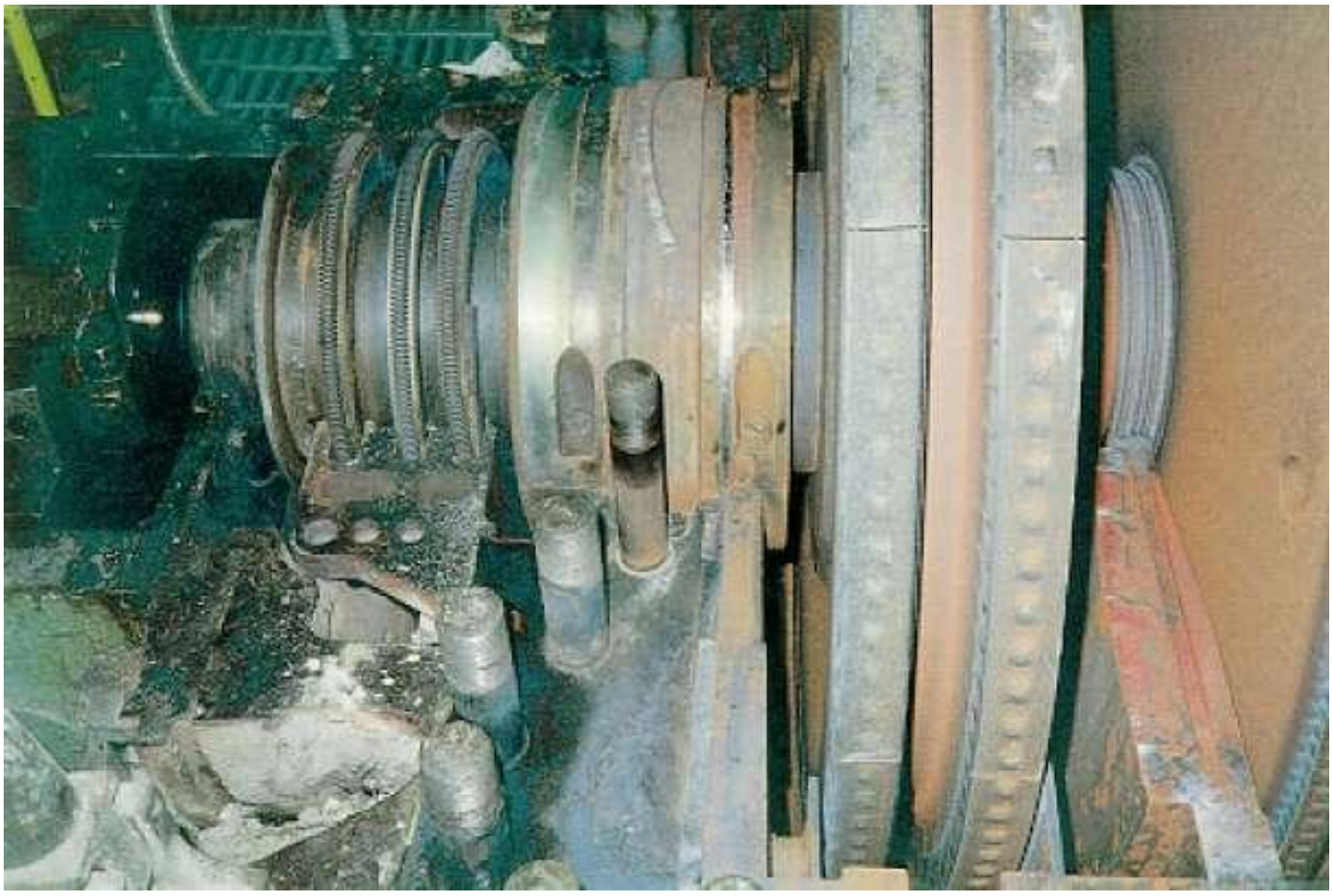


Figure 591. Worn out carbon packing rings

**2.) Labyrinths** mated with shaft serrations or shaft seal strips. Labyrinth seals consist of a number of thin circular strips fastened to the casing. They are made of chrome-alloy and are caulked in place. This is a type of seal designed to prevent steam leakage along the turbine shaft. It is frequently used in conjunction with a water seal gland or with a steam seal. It may be used at the high pressure end.

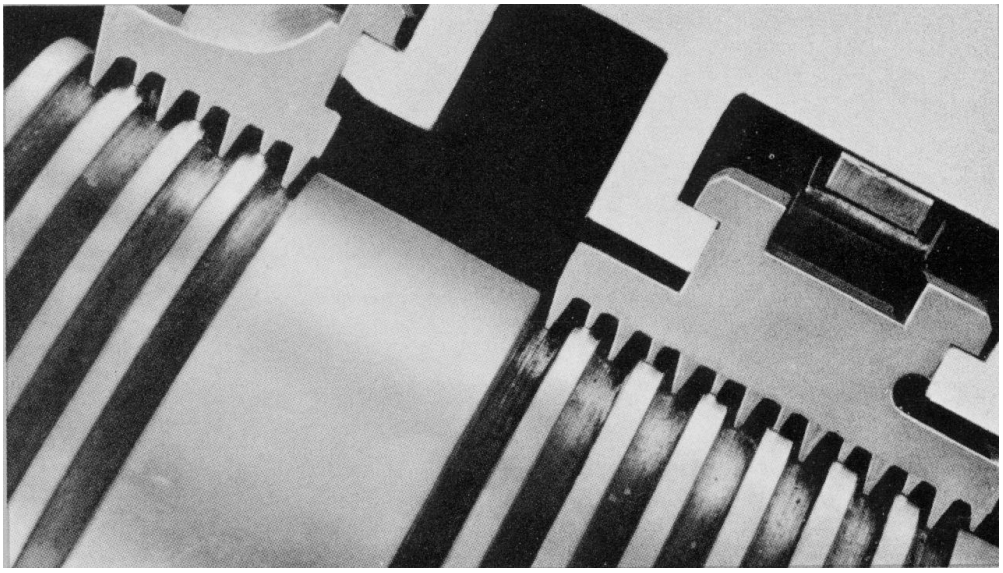


Figure 592. Labyrinths and labyrinth packing

Labyrinth seals work by throttling the steam or sealing medium to a pressure near the pressure into which the steam is discharged. They consist of a drum which turns with the shaft and is grooved on the outside. The drum turns inside a stationary cylinder which is grooved on the inside.

*D.E.S.C. Turbine Operation page 19 D.E.S.C. Simple Turbines page 39*

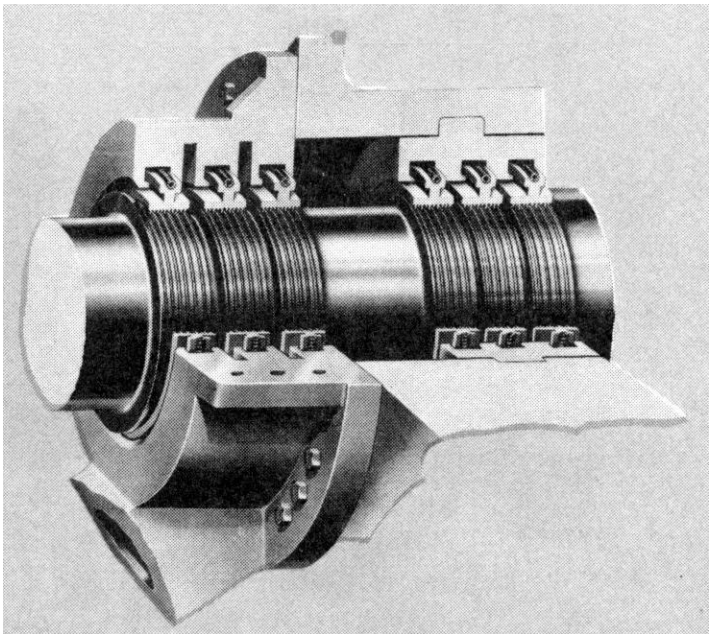


Figure 593. Labyrinth packing

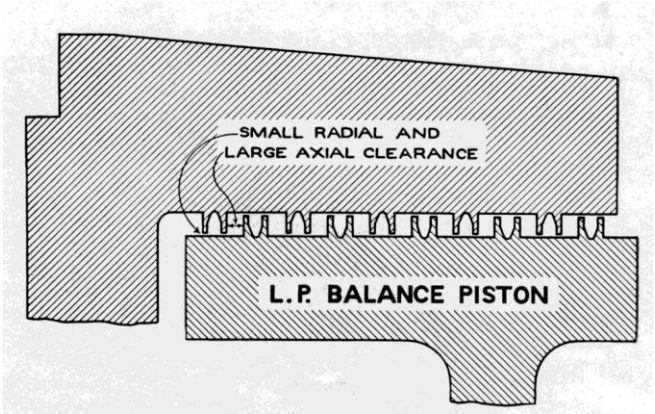



Figure 594. Details of labyrinth packing showing how the turbine can expand without damaging the labyrinths

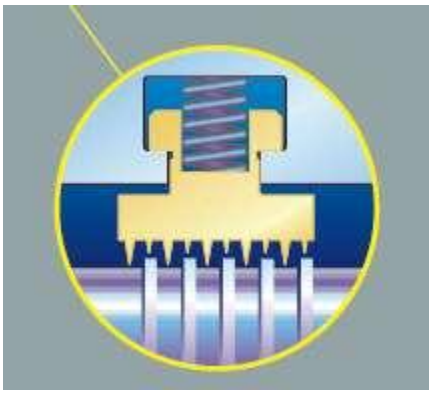


Figure 595. Detail of spring-loaded labyrinth packing

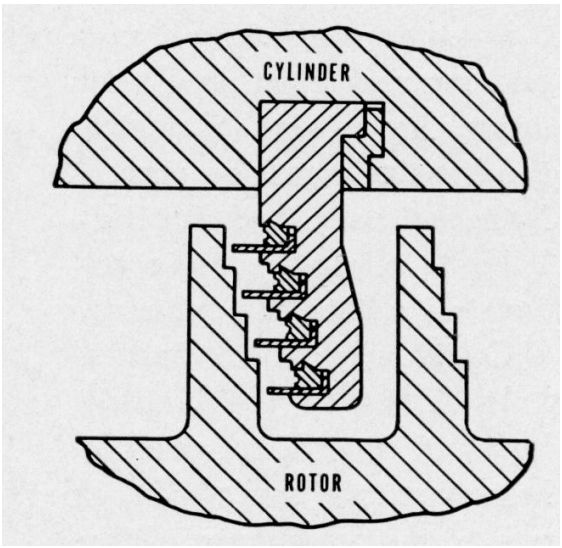



Figure 596. Labyrinths can also seal in a radial as well as axial direction

This is a form of metallic packing designed to force the steam to follow a winding path through the gland. This form of packing frequently used in conjunction with a water seal gland or with a steam seal. It may be used on the high pressure end to prevent leakage of steam out or on the low pressure end to prevent leakage inward. The gland consists of a stationary and rotating element. The stationary element has teeth that fit closely to the moving element to form an orifice between the shaft and the teeth of the gland. Labyrinth seals are also used to seal the high pressure side of the dummy piston from the low pressure side. The gland can be made to seal radially or axially or both and are generally made of thin chrome alloy strips caulked in place.

*D.E.S.C. Turbines page 40 S&V page 51*

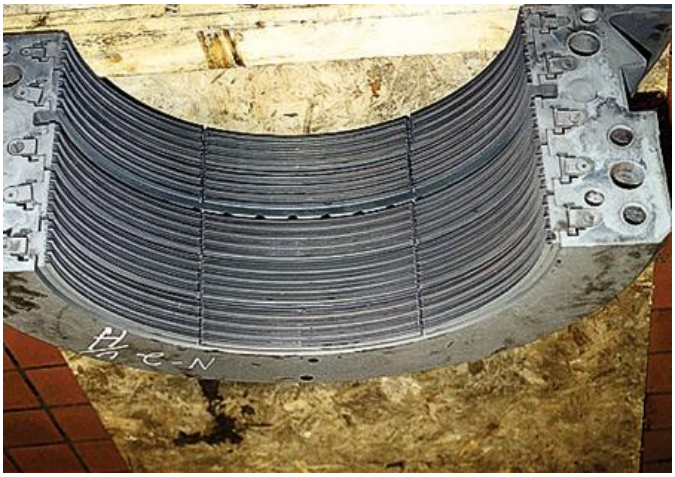


Figure 597. A labyrinth gland removed from a turbine

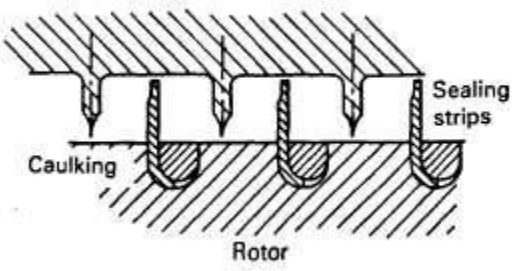



Figure 598. Labyrinth packing acting in an axial direction

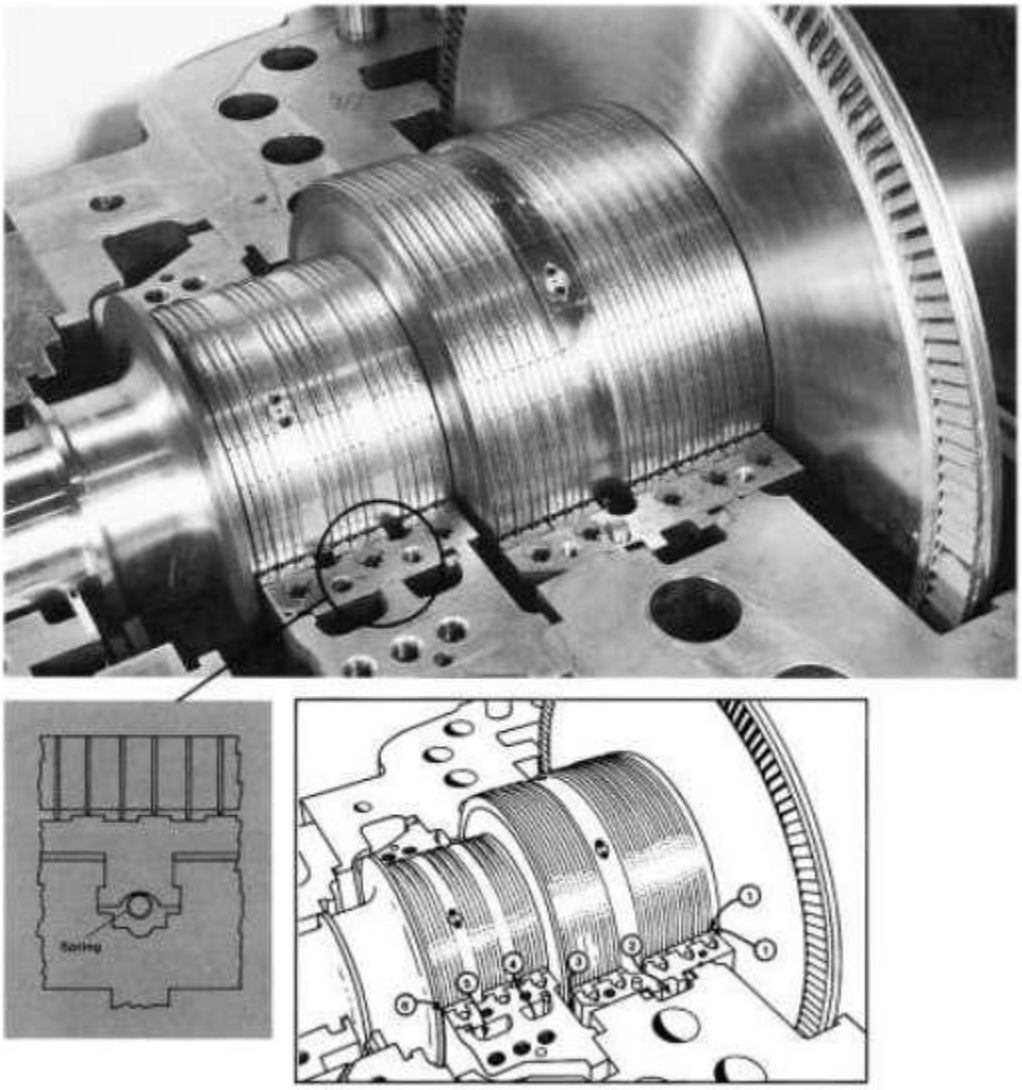



Figure 599. Details of labyrinth packing

Figure 600. Labyrinth packing

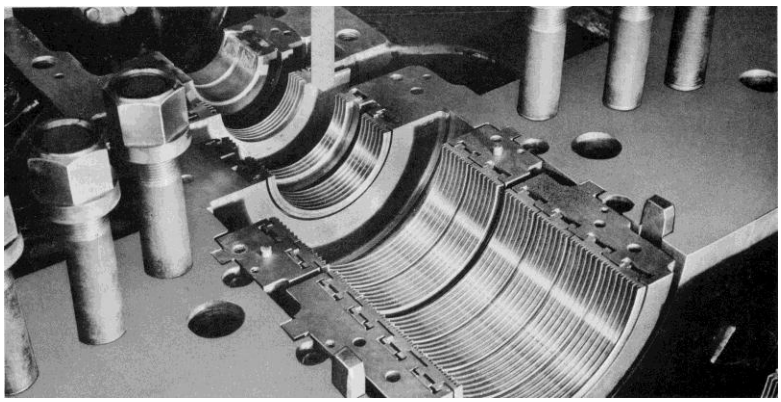


Figure 601. Labyrinth packing can be quite long to lower the pressure enough to stop the steam from leaking out the end

**3.) Water Gland seals** where a shaft runner acts as a pump to create a ring of water around the shaft. Use only treated water to avoid shaft pitting. A water gland is basically a centrifugal pump runner rotating with the turbine shaft. They are always used with labyrinth packing.

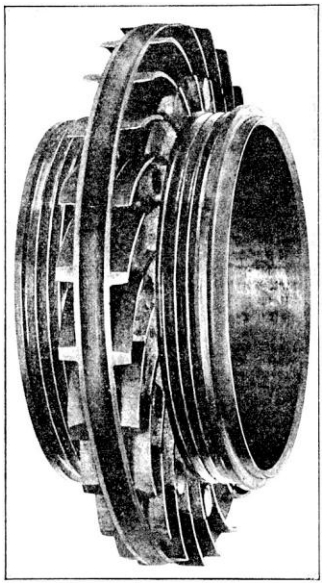


Figure 602. Water gland pump runner

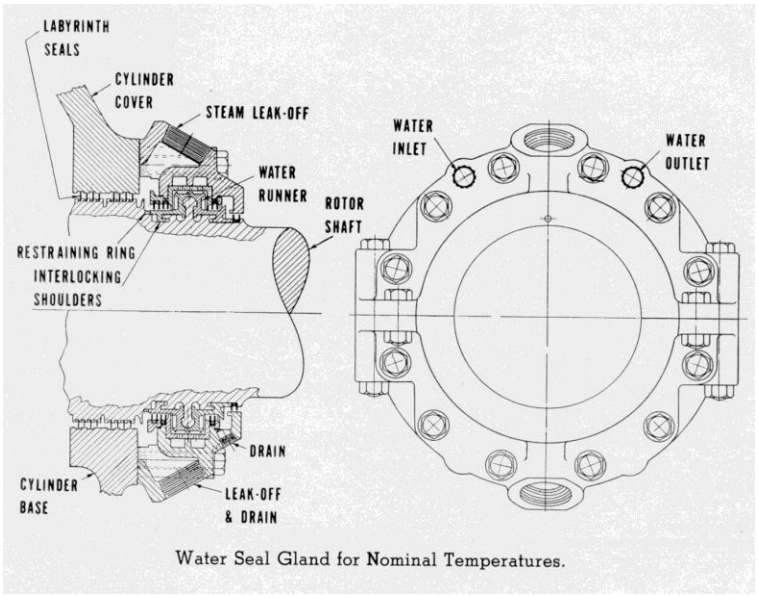



Figure 603. Water gland with water inlet and outlet

## 10. Explain the relationship between labyrinth seals and water glands.

Glands are of great importance in the operation of turbines, as without them high efficiencies could not be obtained. They prevent the leakage of steam from the turbines, and between stages, and block the entrance of air into the turbine when operating condensing. The escape of steam not only causes losses in efficiency, but may unnecessarily heat the bearings if the leak is past the glands on the shaft. Leakage of steam into the bearings furthermore tends to contaminate and emulsify the oil.

Labyrinth packing glands, consist of a series of rings alternately attached to the shaft or rotor and the turbine casing. Due to the number of rings and the small clearance between them, the resistance to the flow of steam or air is a maximum. The outer spaces of the glands are piped to some point in the turbine where the steam pressure is about atmospheric. Any steam which escapes to the outer spaces in the glands is carried back into the turbine through the pipe connections. On the low pressure side the connections are made to a point in the turbine where the pressure is slightly higher than atmospheric. The steam has a slight tendency to escape to the atmosphere thereby preventing the entrance of air through the glands. The admission of air decreases the vacuum and hence the efficiency of operation.

Water-sealed glands, consist of small rotating discs or impellers which are attached to the shaft, and rotate in circular chambers in the turbine casing. Water is admitted into the chambers, and due to the centrifugal action produced by the discs, it is thrown to the peripheries of the chambers. The water thus fills the space between the discs and the chambers, and forms a seal. This type of gland is very efficient, and requires no lubrication. The friction caused by the churning of the water is negligible.

*Engineering Bulletin No. T 36. pages 17-18.*

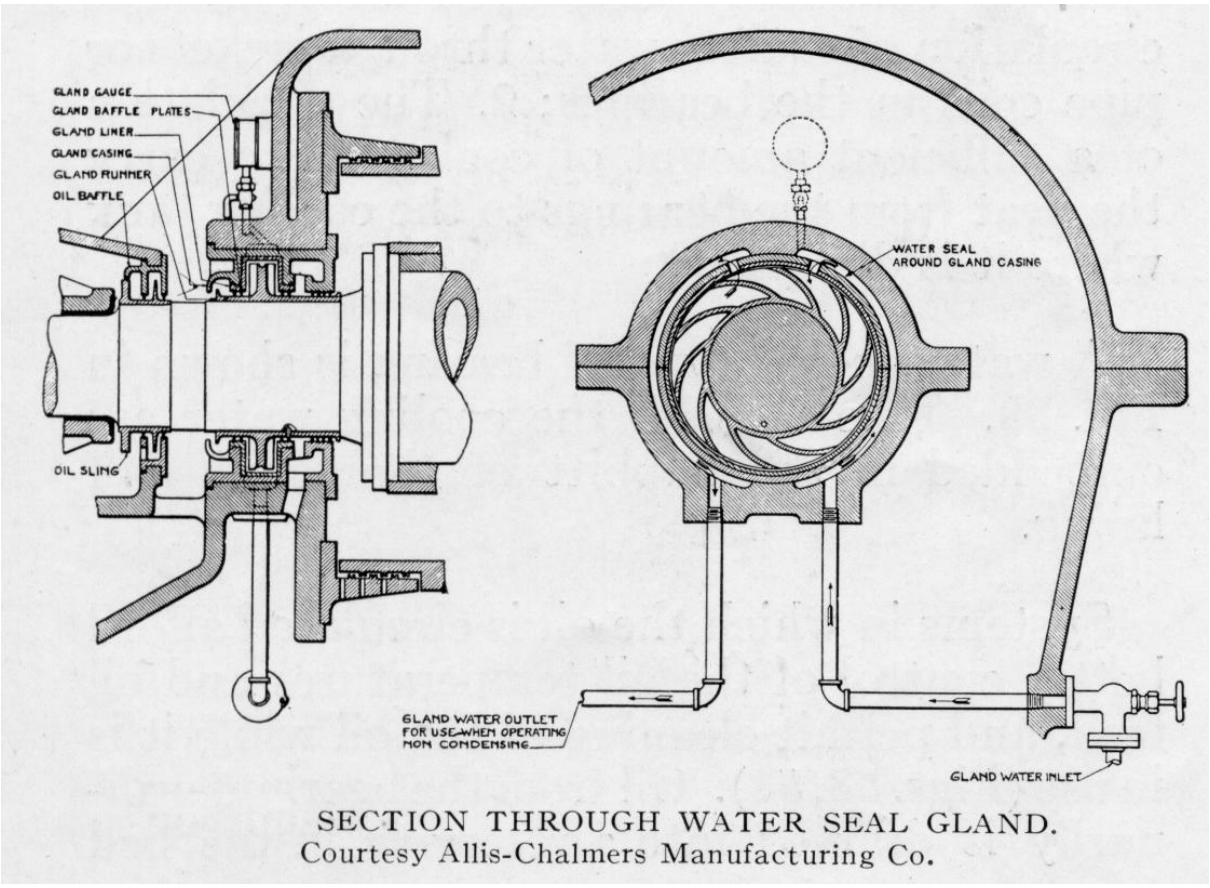



Figure 604. Water gland diagram side and front view showing how the water gland runner resembles a centrifugal pump

Water Glands are basically a centrifugal pump runner - usually used in combination with labyrinth seal. Water is supplied at 3 to 5 PSI. Condensate is used.

*D.E.S.C. Simple Turbines page 36*

Figure 605. Water gland casings for the water gland runner to fit inside

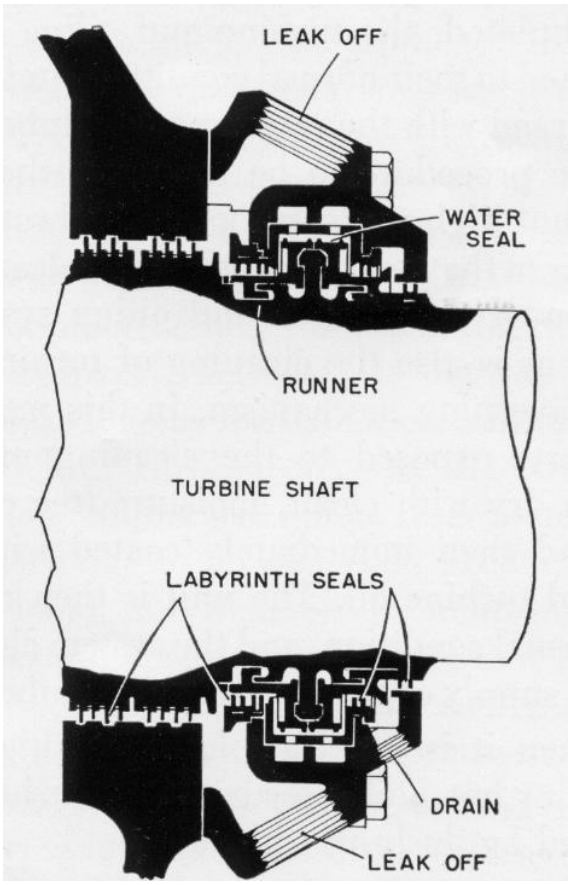



Figure 606. Water gland, side view diagram

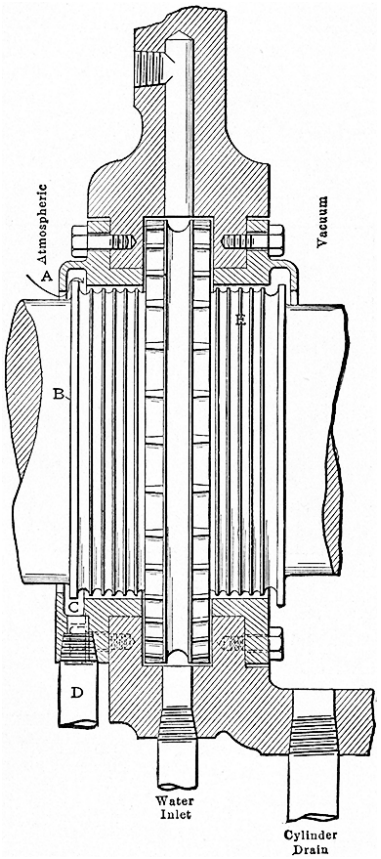



Figure 607. Water gland diagram of a different manufacture, side view

## 11. At what speed do water glands come into play on an electrical generating turbine?

The water gland starts at:

1000 RPM on a 1800 RPM unit.

2000 RPM on a 3600 RPM unit.

## 12. What type of water is used on water glands?

Condensate is always used on water glands. This will prevent formation of scale and dirt particles in the runner casing. The discharge from the casing may be fed back into the boiler feed system, usually to the feedwater heaters.

*D.E.S.C. Simple Turbines page 41*

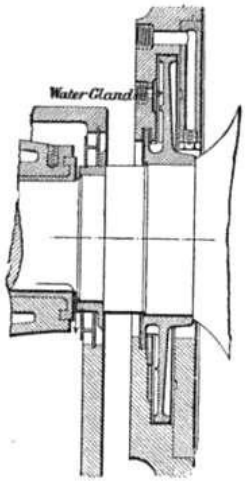



Figure 608. Older model water gland

**4.) Steam seals** use low pressure steam to prevent air infiltration to casings under a vacuum

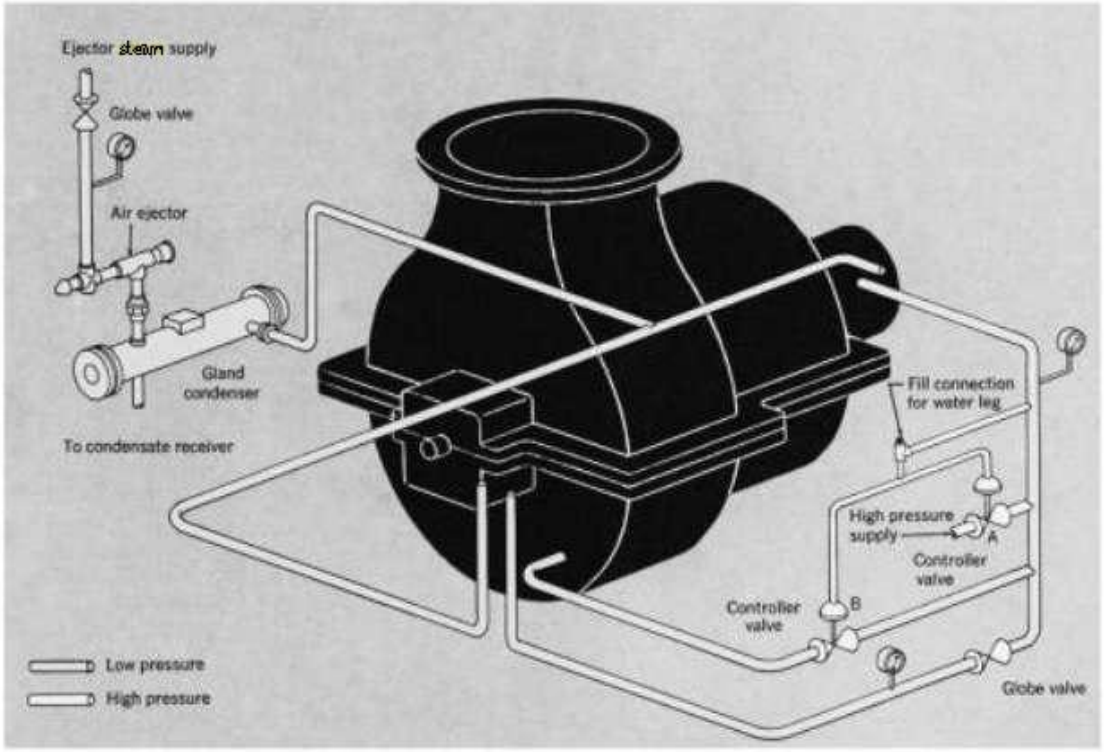



Figure 609. Steam seals and gland condenser

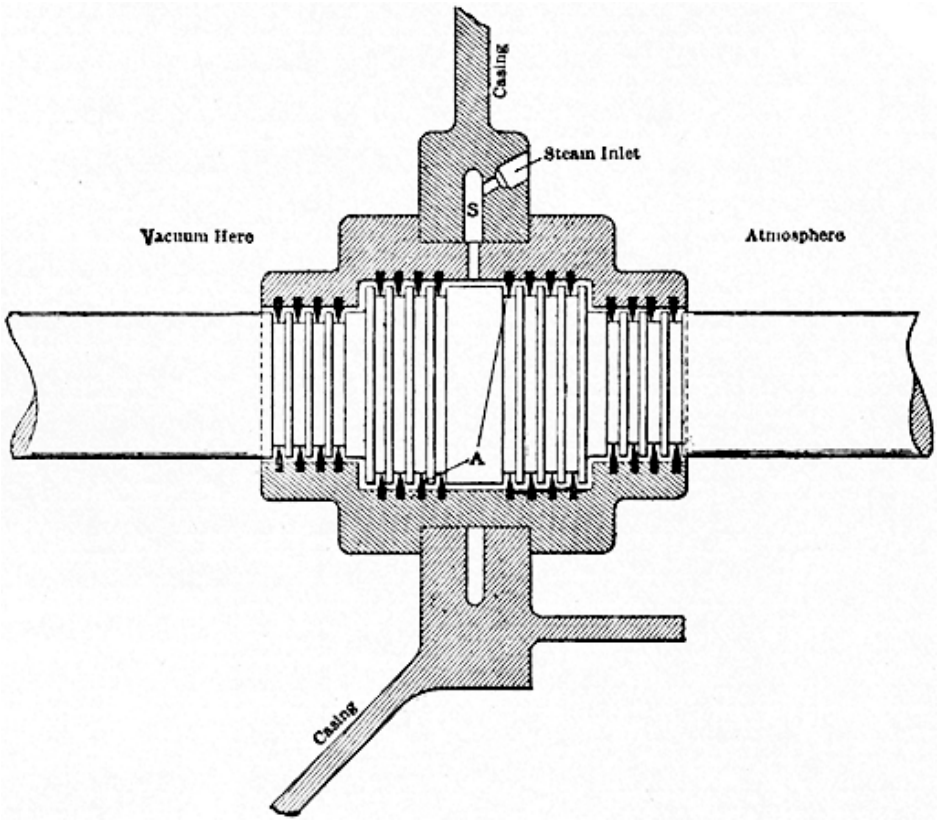



Figure 610. Steam seal showing how air is kept from entering the turbine

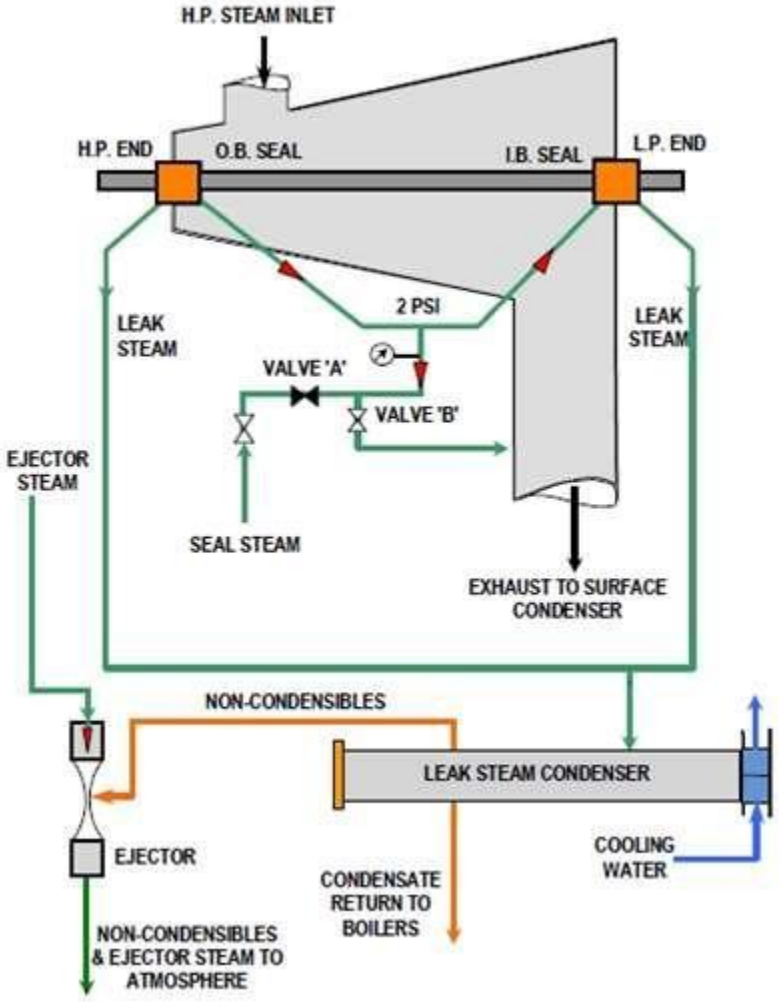



Figure 611. Sealing steam diagram

Figure 612. Showing how the sealing steam is preventing air from entering.

Figure 613. Sealing steam leaks

## GLAND SEAL SYSTEMS FOR TURBINES

Gland Seal Assembly

Ejectors are the most popular choice for Gland Seal Systems for removing air and steam from steam turbine shaft seals. The Type "P" Ejector is ideal for small turbines where flow quantities of steam and air from the shaft seal bleed-off are relatively low. For larger turbines, it is usually advantageous to use a shell & tube (surface-type) precondenser to reduce load to the ejector; and, to recover heat by using condensate in the precondenser. The ejector used with the precondenser can be the Type "P"; or, if reducing steam usage is important, the Type "E".

Figure 614. Ejector and gland steam condenser to prevent sealing steam waste

To prevent rust and loss of efficiency, a Gland Steam Condenser Package is incorporated into the power plant. Operating on a continuous basis, API Heat Transfer's Gland Steam Condenser Package pulls a slight vacuum on the turbine shaft seals by means of vacuum pumps, centrifugal blowers, or steam ejectors. This allows capture of the leaked steam and air mixture.

Figure 615. Another brand of sealing steam condenser

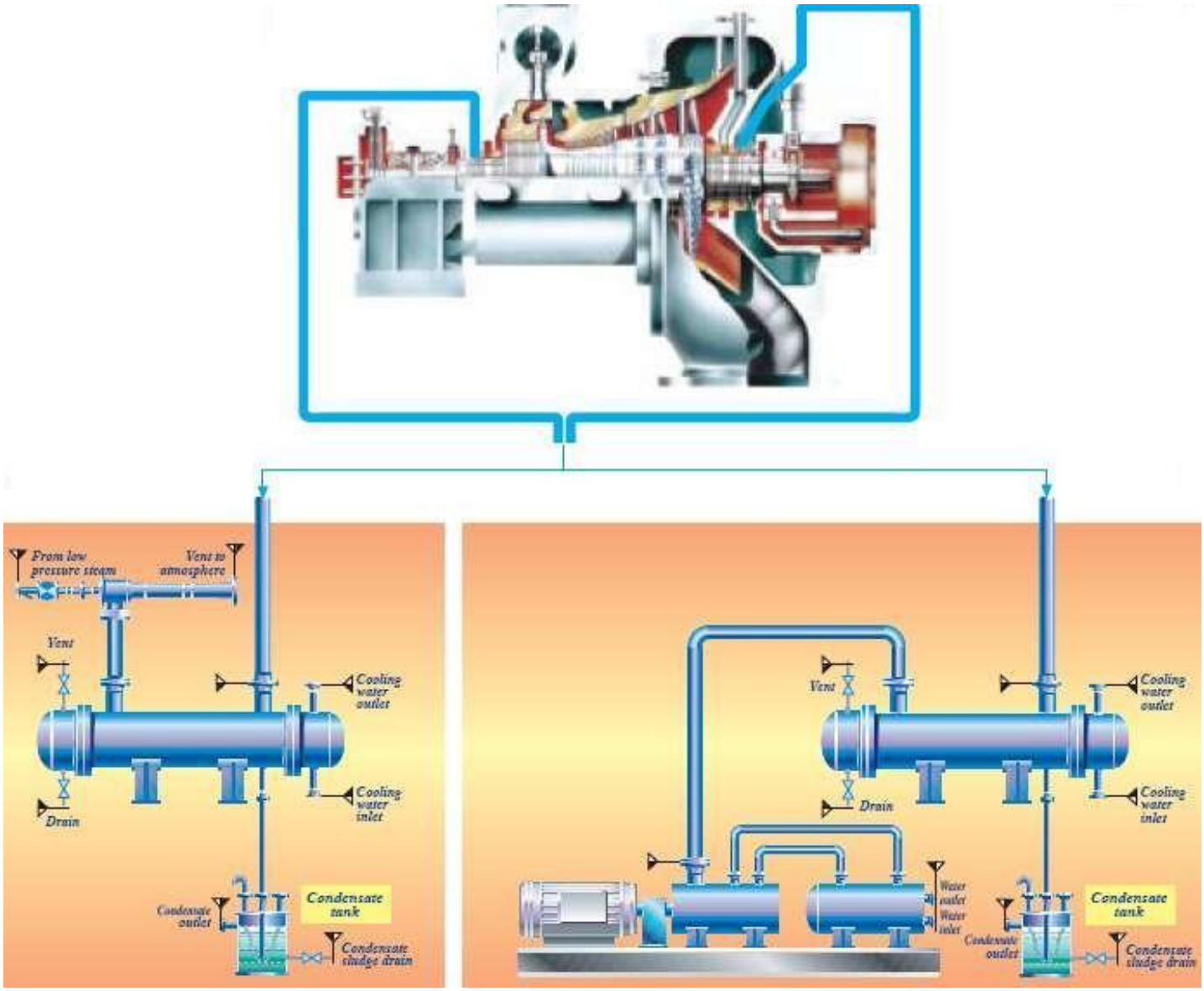



Figure 616. Complete system for capturing gland sealing steam

The uncontrolled loss of steam is uneconomical. The Gland and Vacuum Seal System is able to eliminate steam vapors around the machine which are usually toxic due to additives found in the machine and reduce the humidity around the machine resulting in safer operation of all electric devices installed in the area.

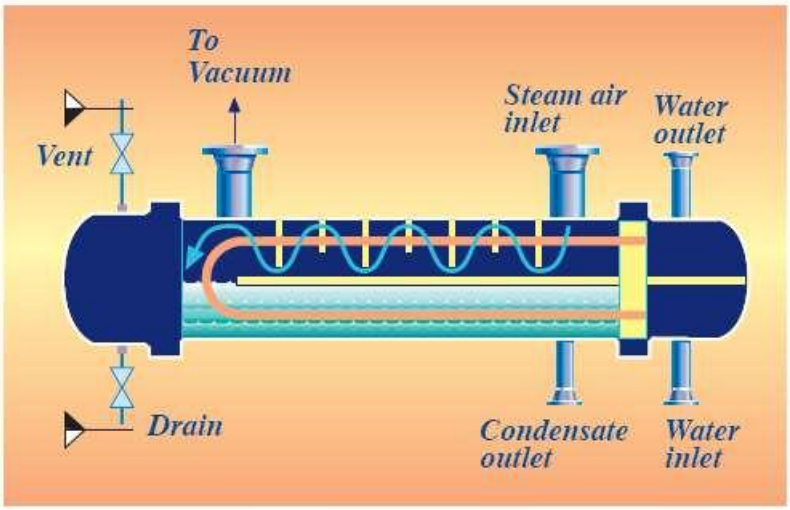



Figure 617. Gland seal steam condenser

### 5.) Brush Seals

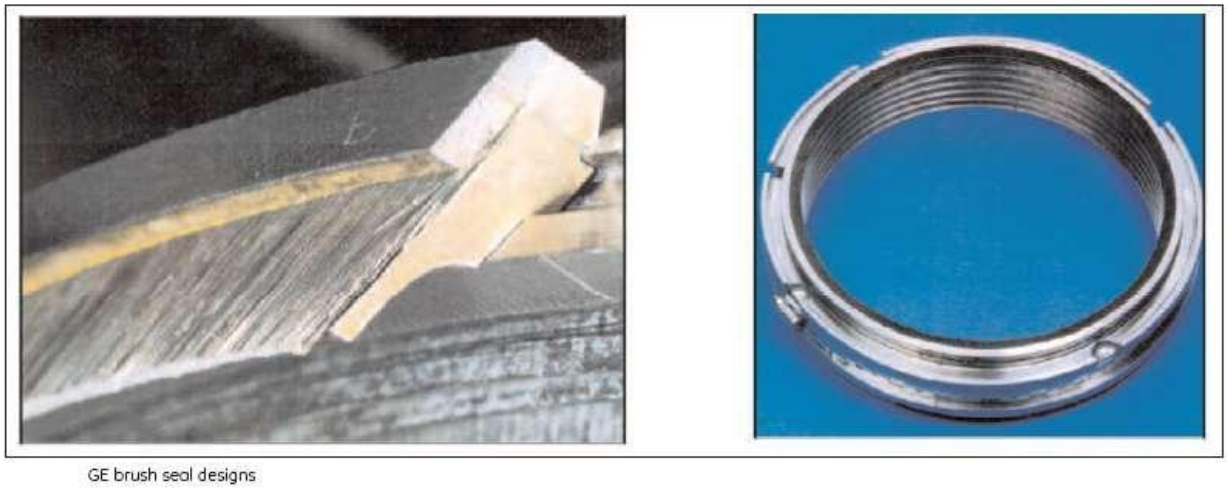



Figure 618. Brush seals are used in conjunction with labyrinth seals to reduce steam leakage

### 13. What are brush seals?

Brush seals are specially designed bristles that maintain a minimum clearance between the brush assembly and the rotor without actually touching the rotor. The fact that they do not touch eliminates any possibility of vibration being induced in the turbine by contact with the brush seals. They are used in conjunction with labyrinth seals

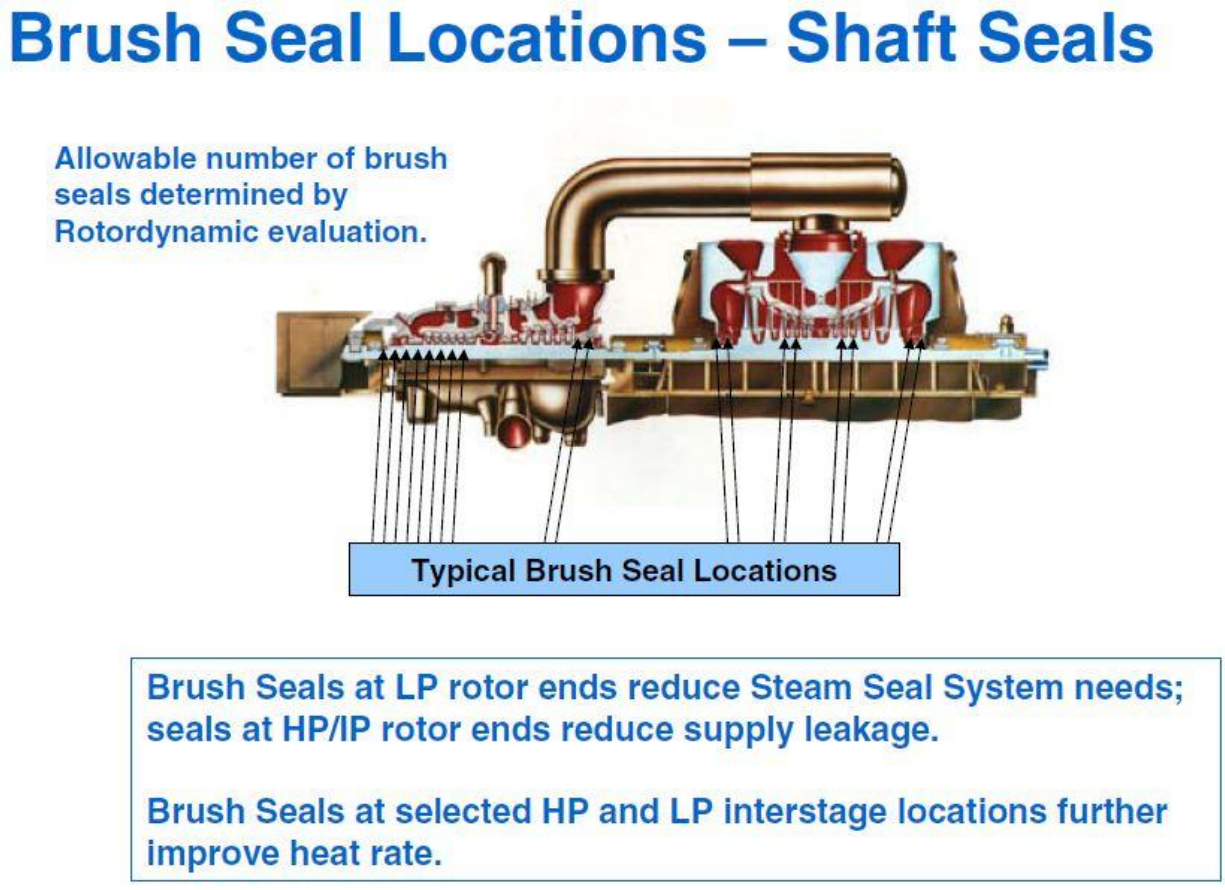

Brush Seal Locations – Shaft Seals
Allowable number of brush seals determined by Rotordynamic evaluation.
Typical Brush Seal Locations
Brush Seals at LP rotor ends reduce Steam Seal System needs; seals at HP/IP rotor ends reduce supply leakage.
Brush Seals at selected HP and LP interstage locations further improve heat rate.

Figure 619. Brush seal locations

To prevent rubbing at start-up, create a packing ring with a large clearance to allow for the thermal distortion and vibration so that the labyrinth teeth do not come in contact with the rotor. The clearance tightens during operation to minimize leakage. Turbocare's brush seals are made from Haynes 25, an alloy of cobalt, nickel, chromium, and tungsten.

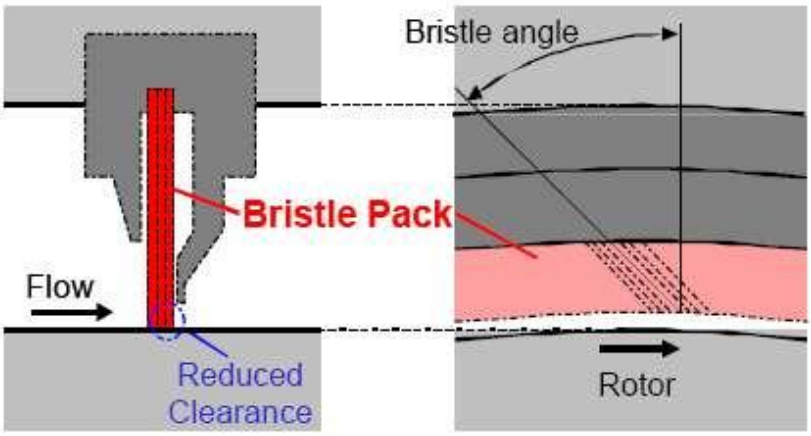



Figure 620. Brush seal bristle angle

Figure 621. Brush seal end view

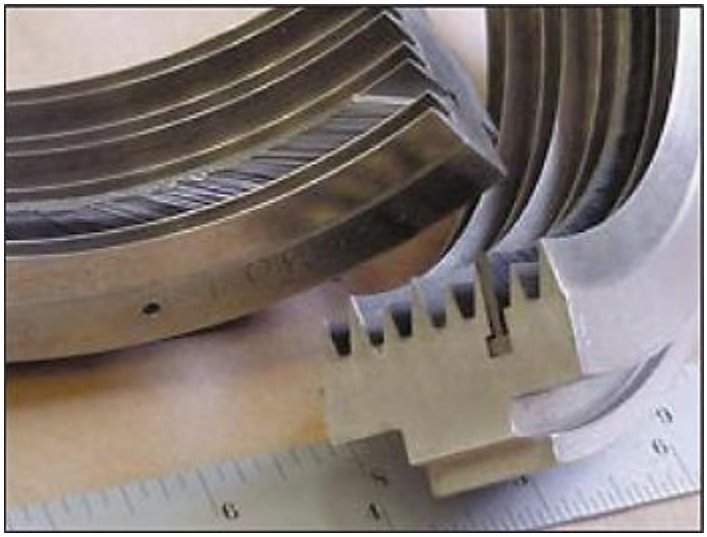


Figure 622. Brush seal size comparison to a steel ruler

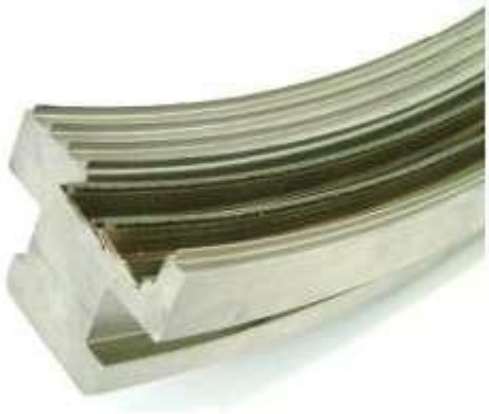


Figure 623.

Spring-Backed Seal Segment with Two-Stage
Brush Seal and Labyrinth Fins

## 6.) Mechanical Seals

Mechanical face seals can reduce steam leaks more effectively than traditional carbon ring or labyrinth gland-sealing systems. This enables turbines to reduce contamination of the oil system with steam and to run with lower steam leakage. Mechanical face seals are very durable in their intended applications, but reliability and long-term operation of steam turbines fitted with them depends largely on conditions of service.

Figure 624. Mechanical seal assembly

Figure 625. Mechanical seal on the shaft

Figure 626. Mechanical seal diagram

Figure 627. Dresser Rand mechanical seal for turbines

a simple mechanical seal design has 7 components:

1. Stationary component; commonly referred to as 'the seat'.
2. Stationary component sealing member.
3. Rotating component.
4. Rotating component sealing member.
5. Spring.
6. Gland plate.
7. Clamp ring.

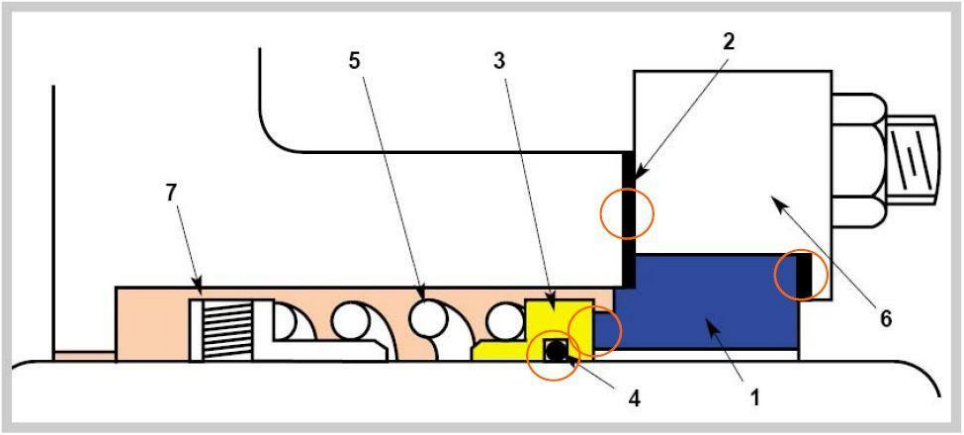



Figure 628. Mechanical seal components

The rotating component (3) is pressed against the stationary component (1) by spring pressure. The mating surfaces are lapped to be extremely flat. The leakage is in the form of vapor that is usually not visible. This leakage is necessary to lubricate the faces of the seal to prevent wear. The spring pressure stops any leaks when the turbine is stopped and the faces of the seal come in contact with each other. One face is usually carbon and the other face is hardened steel made with chromium or nickel for corrosion resistance.

Figure 629. Mechanical seals installed in a turbine in place of carbon ring packing

## 7.) Wavy Seals

Wavy seals have waves and tilts with a flat annular circumferential seal dam on one edge to stop leakage when the turbine is stopped. The static steam and moving steam created by the tilts and waves of the ring create waves of amplitude that diminish as they approach the seal dam. The rotating and stationary faces are pushed toward each other by springs while being held apart and lubricated by the steam. The faces can be silicon carbide or Nickel alloy 718 inconel which has good corrosion resistance, resistance to chloride, sulfide and stress corrosion cracking. Silicon Carbide has good wear resistance and low thermal expansion with a high thermal conductivity.

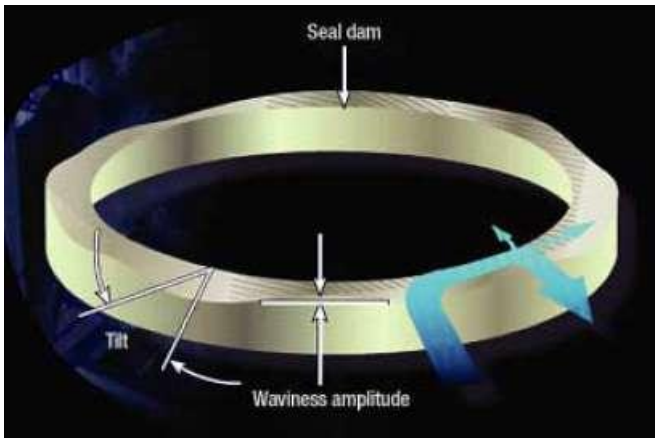



Figure 630. Wavy seal design

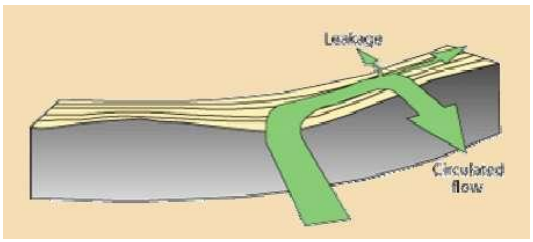



Figure 631. Wavy seal leak path away from seal dam

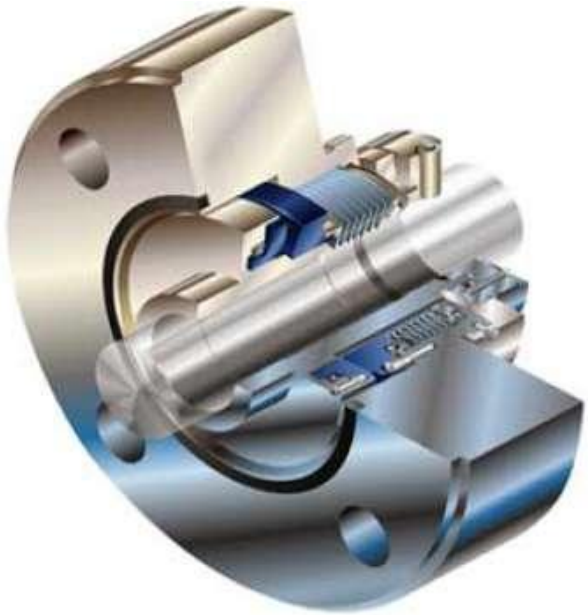


Figure 632. Phantom view of wavy seal installed on the shaft

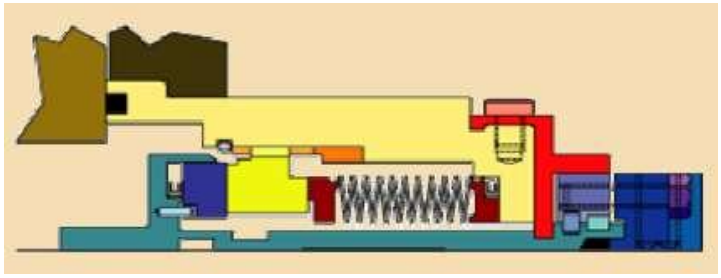


Figure 633. Wavy seal side view diagram

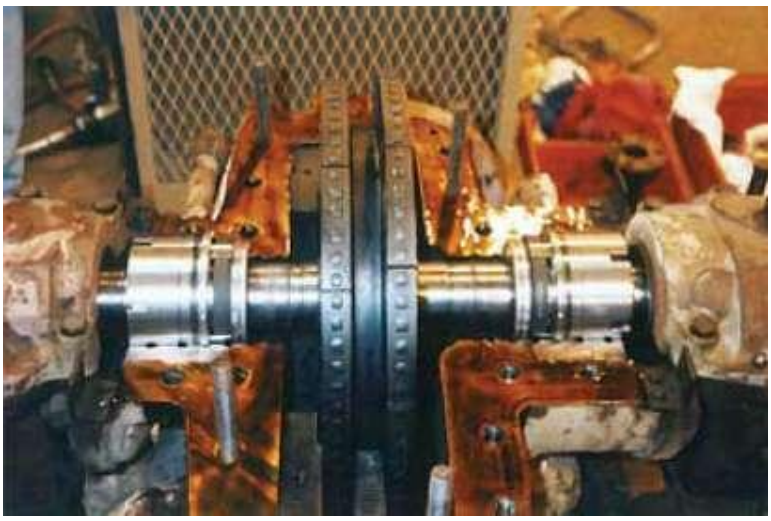


Figure 634. Wavy seals installed in place of carbon ring packing

# Chapter 16 Turning Gears

## 1. What is a turning gear? How is it made? Why? How fast does it turn?

A turning gear generally consists of a small capacity motor (5 to 20 horsepower), a speed reducer, and a driving gear assembly. It is used for turning the rotating parts of a turbine at slow speed (2 to 20 R.P.M.) during the cooling off period to prevent distortion in turbine elements and to avoid localized cooling of the shaft. It is also used in starting up for uniform heating.

*S&V page 57*

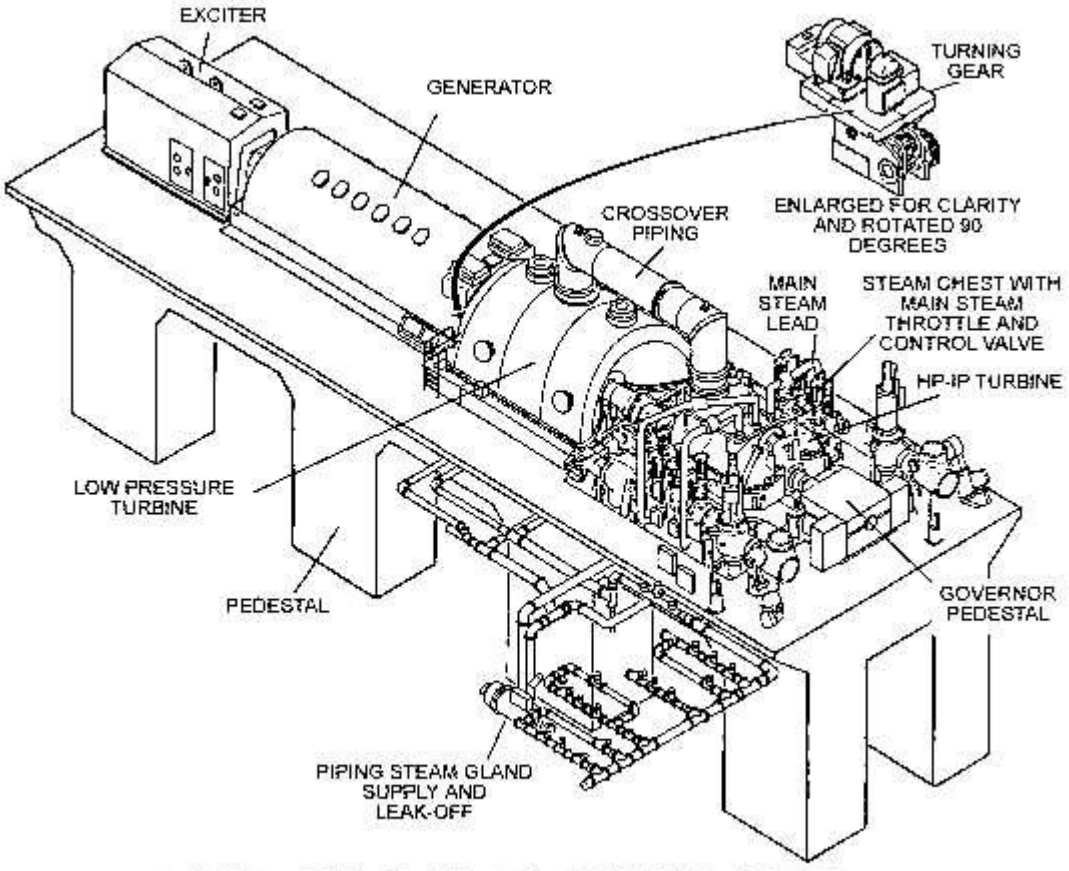
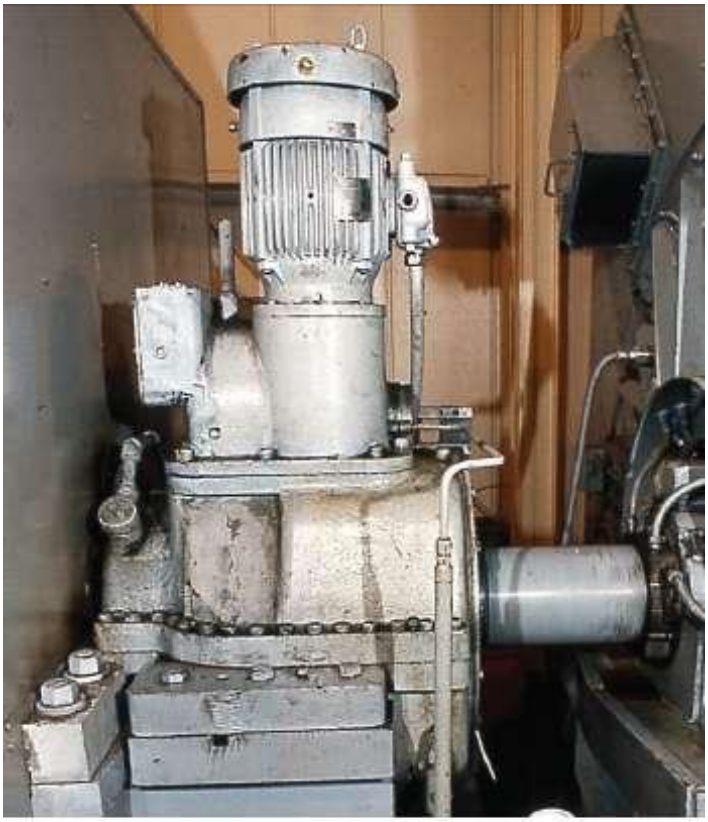



Figure 635.

## 2. Tell what you can about turning gears? How are turning gears lubricated?

Turning gears consist of essentially a large gear built onto the turbine shaft near the coupling and driven by an electric motor through a suitable reducing gear arrangement. The motor usually mounts on the turbine exhaust hood and drives the turbine spindle at speeds of 1/2 to 3 RPM while warming and cooling. When the spindle is turning at this low speed, only low pressure oil need be supplied to the bearings at about half the normal operating flow.

The turning gear turns the turbine rotor slowly during shutdown, and prior to starting the turbine. Turning the rotor slowly ensures that it is heated or cooled evenly. If the rotor is allowed to come to a rest when hot, temporary bowing and excessive vibration can result. Distortion of the turbine casing also results because the hotter steam rises to the top of the casing. The turning gear consists of an electric motor driving a speed reducing gear train. The gear train drives a large "clash pinion" or pinion gear as it is often called, that can swing toward or away from the turbine rotor. A "bull gear" is usually mounted on the outside diameter of the coupling between the turbine and generator.



TURNING GEARS FOR
LARGE TURBINES

Figure 636.

## 3. What is the purpose of a turning gear?

Heat must be prevented from warping the rotors of large turbines or high-temperature turbines of 400°C or more. When the turbine is being shut down, a motor-driven turning gear is engaged to the turbine to rotate the spindle and allow uniform cooling.

## 4. What is the turning gear of the rotor?

Turning gear is a large gear built into the shaft near the coupling end. An electric motor drives the shaft through a reduction gear at 1 to 40 RPM.

The gear should be in use during warm-up and cool-down and for periods of several days. By use of the turning gear the spindle as well as the casing is uniformly warmed up and cooled down. Also equal expansion is insured in case any steam is leaking past the control valve. Turning gears also reduce start-up time and prevents bowing and sagging of the rotor.

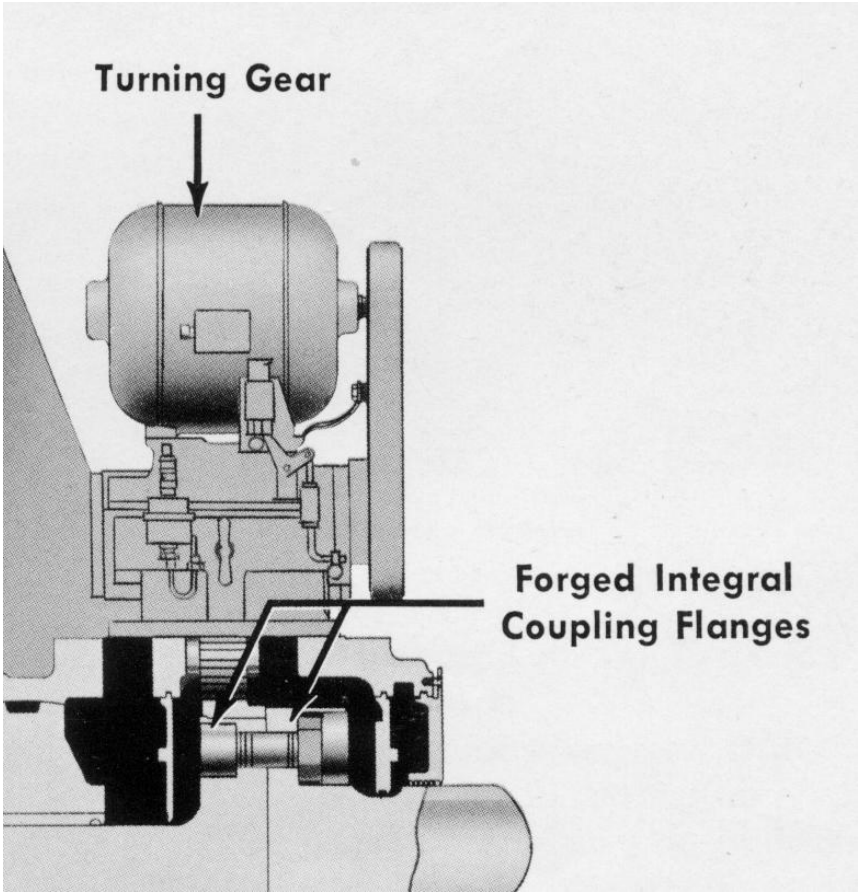



Figure 637. Turning gear mounted between the casings of the turbine

## 5. How fast does a 10 MW turbine roll on the turning gear?

1 to 30 R.P.M.

*D.E.S.C. Modern Turbines page 16*

1 to 3-l/2 R.P.M.

*S&V page 58 and page 120*

## 6. How do you remove or disengage the turning gear?

Turning gears have a spring clutch which keeps the turning gear in contact with the rotor. When the rotor starts to rotate at a speed above a predetermined speed the spring that provides tension to keep the turning gear on the rotor, kicks the turning gear away from the rotor and keeps it out of the way.

*Bob Secorski, Shift Engineer- Mistersky Power Station*

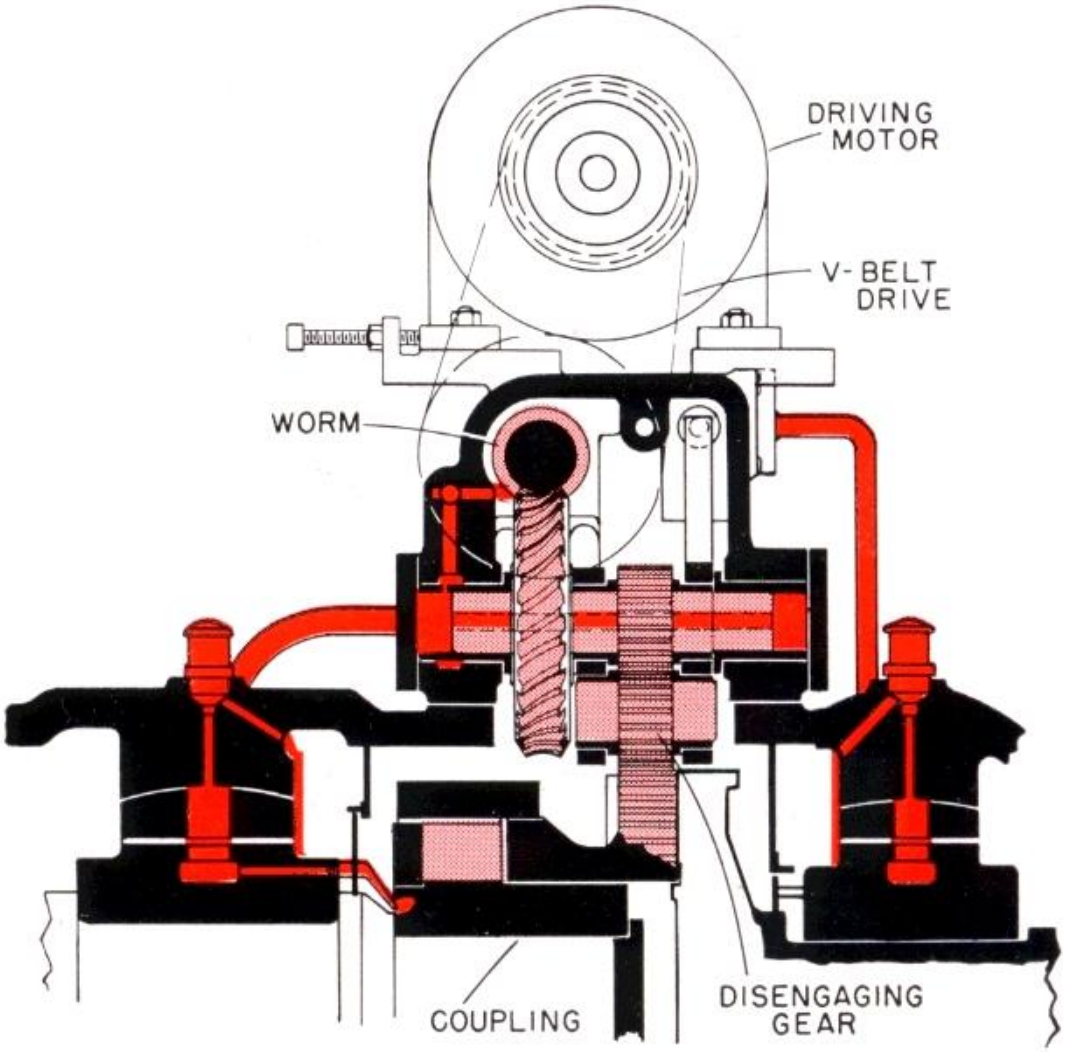



Figure 638. Turning gear with automatic disengaging gear

# Chapter 17 Reduction Gears

## 1. What type of gearing is found in turbine reduction gearing?

Reduction gears are used to deliver the power from turbines to equipment that operates at less than turbine speed. These gears are usually of the herringbone type, enclosed in an oil tight casing, with babbitted bearings for the shafts. Flexible couplings usually connect the pinion and gear shafts to the turbine and driven machine.

*S&V page 107*

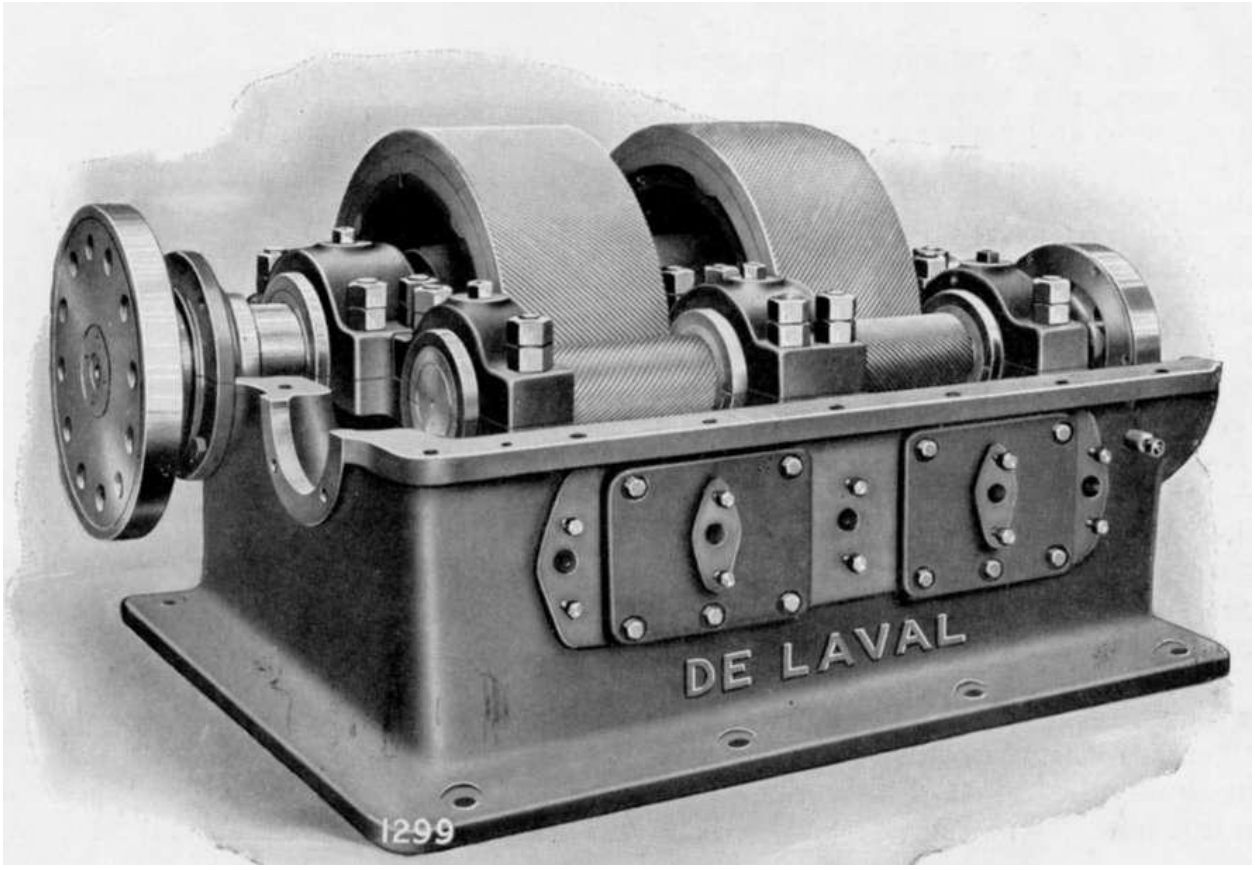



Figure 639. DeLaval reduction gearing with cover removed

The function of a steam turbine reduction gear is solely to reduce the rotative speed of the turbine shaft to a suitable speed for driving some other machine. Since turbines operate efficiently only at high speeds and since many mechanically driven machines must be operated at low rotative speeds, it is obvious that these low speed driven machines cannot be coupled directly to the turbine. A reduction gear does not reduce the speed of the turbine shaft. Rather, the turbine shaft transmits its power through the reduction gear to another shaft which then is connected to the driven machines. They are three (3) types of reduction gears: single, double, and epicyclic. The transmission efficiency of a reduction gear is very high; it may exceed 98 per cent.

## 2. What is the maximum possible reduction with a single set of gears?

The maximum reduction with a single set of gears is 12:1. This is because of the number of teeth on each of the gears, a ratio higher than this would not allow the gears to mesh properly.

*"The Navy Handbook, Boilerman 2&3."*

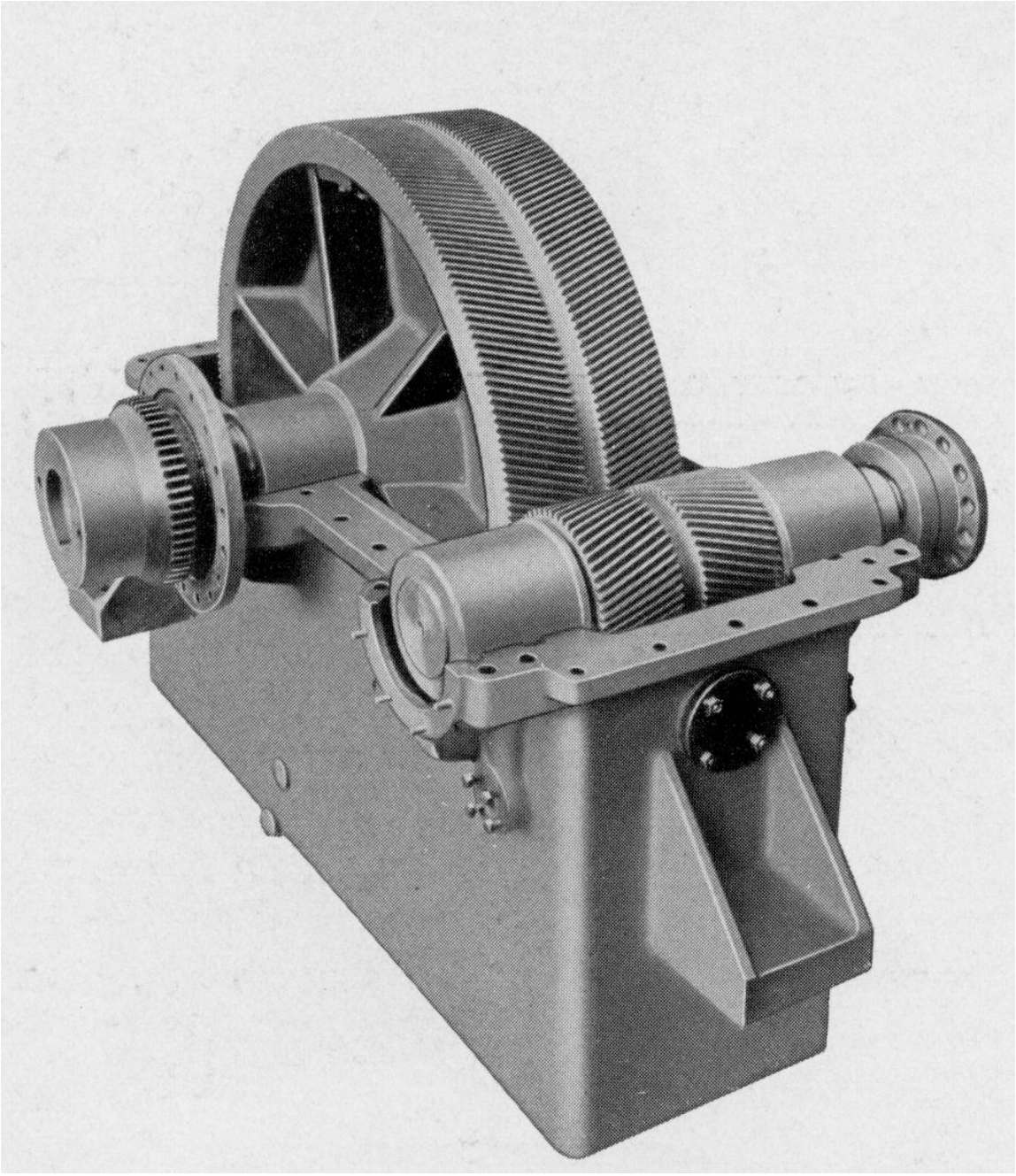


Figure 640. Double Herringbone Reduction gear

Figure 641. Lifting the cover of a reduction gear

Figure 642. Reduction gears can be very large

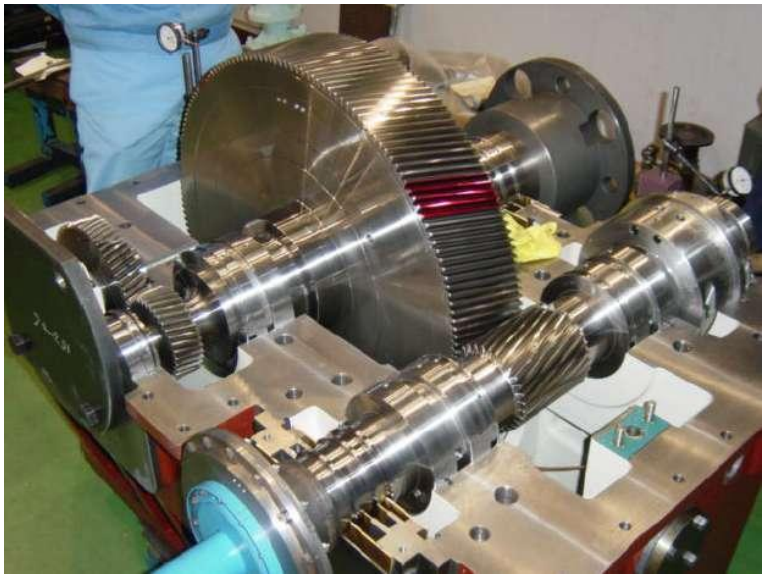


Figure 643. Mitsubishi single herringbone reduction gear for a medium sized turbine.

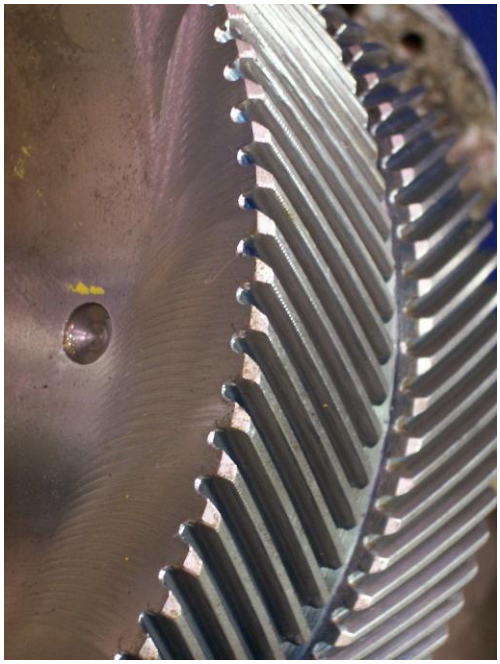


Figure 644. Double herringbone reduction gear

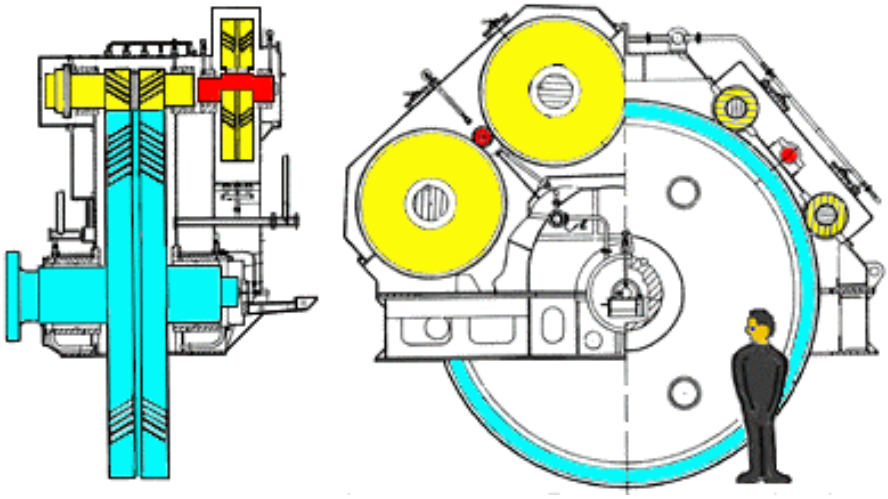


Figure 645. Double herringbone reduction gear with man for size comparison

# Chapter 18 Couplings

## 1. How will you detect that misalignment is the probable cause of excessive vibration?

The coupling to the driven machine is to be disconnected. The turbine is to be run alone. If the turbine runs smoothly, either misalignment, worn coupling or the driven equipment is the cause of the trouble

## 2. How can the coupling misalignment be rectified?

The bolts holding the flanges together are to be tightened. The coupling is to be checked for squareness between the bore and the face. At the same time axial clearance is to be checked. Using gauge block and feeler gauges, the gap between coupling faces 180$^{o}$ apart is to be measured. After rotating the coupling-half 180$^{o}$, the gap at the same points is to be measured. After this, the other coupling is to be rotated 180$^{o}$ and the gap at the same points is to be re-measured. These measures should come within a few thousands of an inch. Dividing the coupling faces into four intervals, the distance between the coupling faces at this intervals is to be measured with the aid of a gauge block and feeler gauges. These gap measurements should come within 0.005 inch for proper angular shaft alignment. After proper alignment at room temperature, the two halves of the coupling are to be connected.

Figure 646. Coupling misalignment

Figure 647. Mounting the laser alignment tools on the shaft

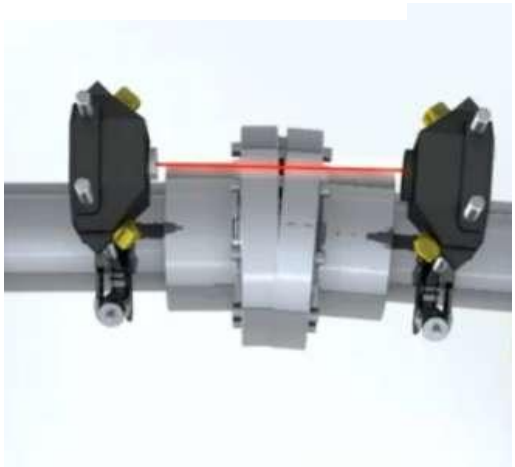


Figure 648. Starting the alignment

Figure 649. Continuing to align the equipment so that the couplings can be tightened evenly

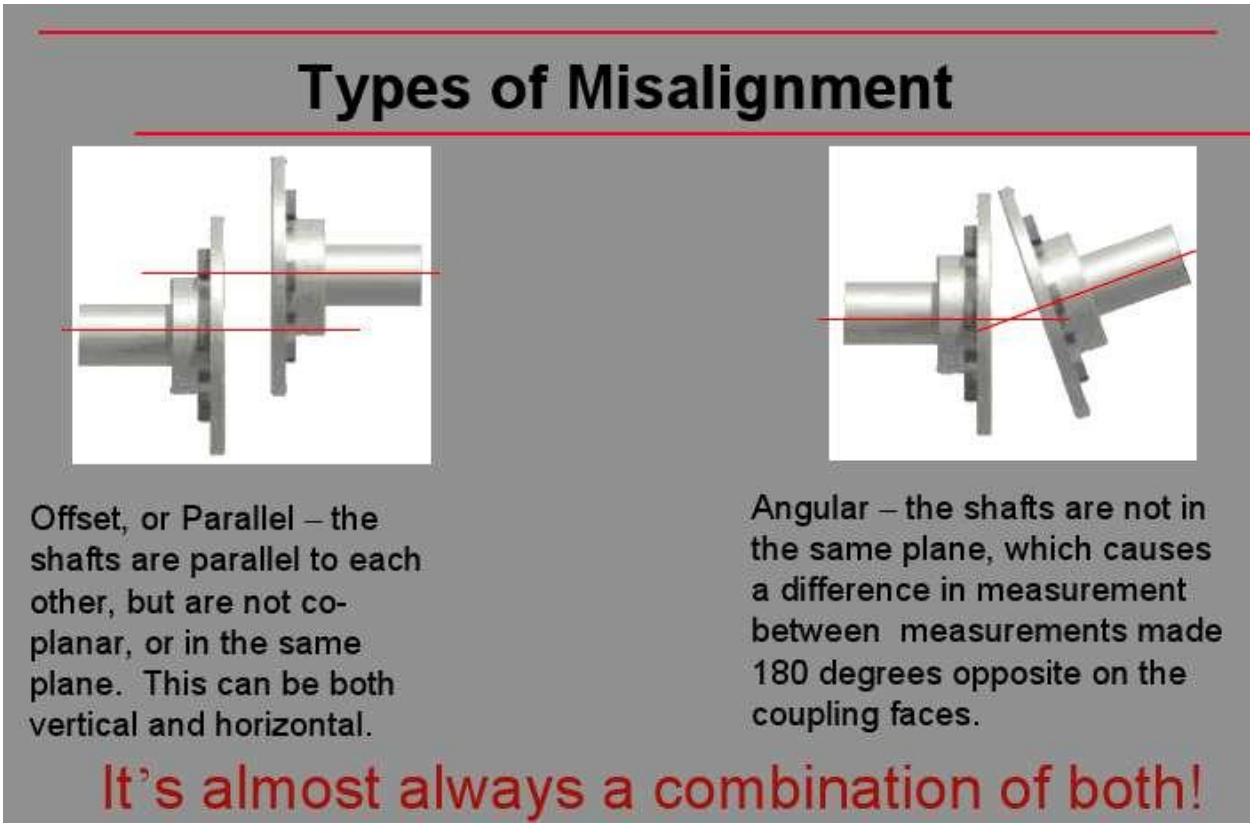

Types of Misalignment
Offset, or Parallel – the shafts are parallel to each other, but are not co-planar, or in the same plane. This can be both vertical and horizontal.
Angular – the shafts are not in the same plane, which causes a difference in measurement between measurements made 180 degrees opposite on the coupling faces.
It's almost always a combination of both!

Figure 650. Types of misalignment

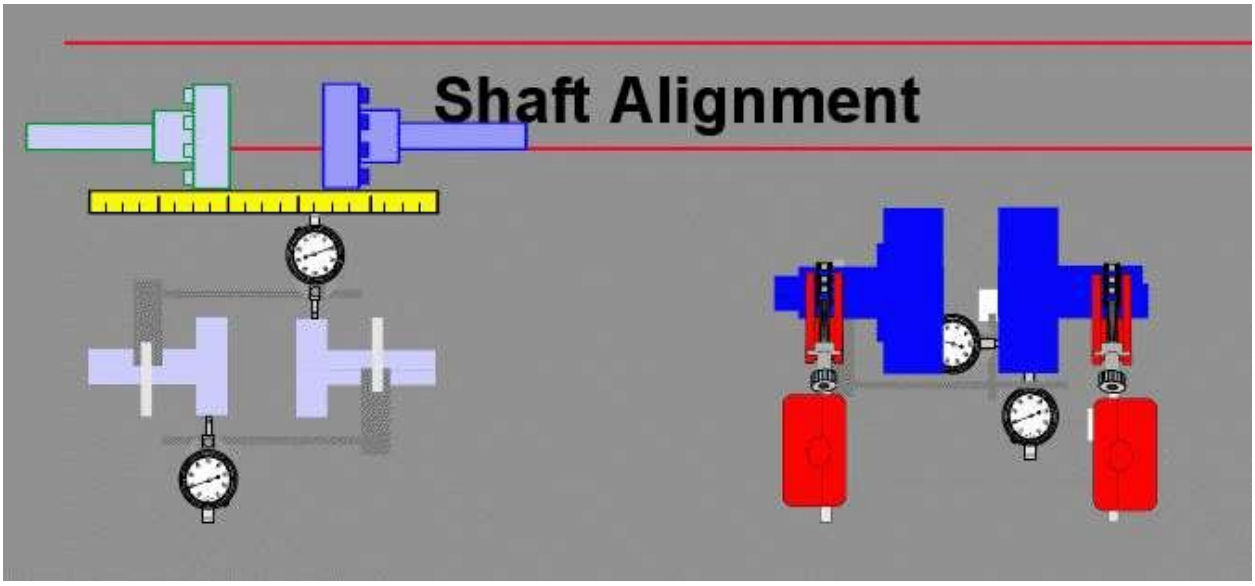



Figure 651. Alignment methods, straight edge, dial indicators, and laser alignment

### 3. What are couplings used for? How are they made? Explain or draw types used. How does a coupling affect setting up of a turbine?

Couplings are used to connect the turbine and driven equipment. They may be rigid or flexible. Made of carbon steel. A small amount of misalignment can be tolerated, but the degree results in a proportionate amount of wear.

Figure 652. Rigid turbine coupling

Figure 653. Rigid turbine coupling

Figure 654. Flexible crowned tooth turbine coupling

Figure 655. Another style of flexible coupling

## 4. A turbine reduction gear driven centrifugal pump has how many couplings and are they rigid or flexible?

Two flexible couplings

Steam turbine couplings are of two (2) types: 1) rigid 2) flexible.

Rigid couplings are employed principally on small turbines and only where both the coupled turbine and driven shaft are supported on only two or three bearings. Where four bearings are used, two for the turbine and two for the driven shaft, a flexible coupling is always employed.

The purpose of flexible couplings in steam turbine drives is to provide for any slight inequality in the wear of the bearings, to permit axial adjustment of the turbine spindle, and to allow for differences in expansion. It is obvious that two shafts, each supported on two bearings, would be bent by any deviation of their bearings from one straight line. Furthermore, it is very difficult to align four bearings exactly in a straight line, and if they are aligned, to maintain them so. Hence, and to permit axial adjustment of the two coupled shafts a flexible coupling is employed

*Croft Steam Turbines 2nd Edition page 175*

Two couplings are required per pump and due to the fact that perfect alignment is difficult to obtain and maintain some type of flexible coupling is generally used. Flexible couplings allow for some slight misalignment between the shafts due to normal wear and settling.

One at either end of the reduction gear or two total and they are both flexible couplings.

In a gear-connected steam-turbine drive, a suitable flexible coupling is used on each side of the gear.

*Steam Power Plant Auxiliaries and Accessories page 161, first edition page 134, D.E.S.C. Turbines page 13*

In most turbine applications, the connection between the turbine and the driven equipment is made by a coupling. Couplings are used also to connect the high pressure and low pressure spindles in some tandem types of turbines. Couplings may be of simple rigid construction bolted or otherwise fastened together.

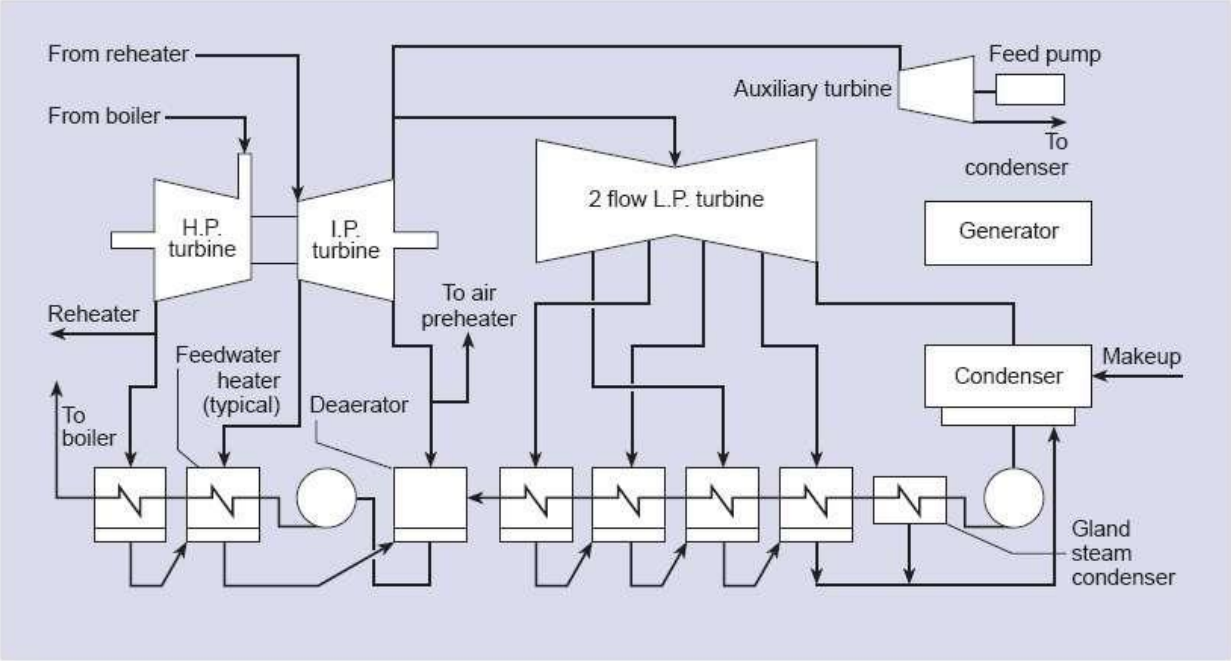
Most often however, some form of flexible coupling is employed. The smaller sections have gear teeth around the outside and are keyed to the shafts. These teeth in turn mate with gear teeth cut on the inside of the sleeve, both halves of which are then bolted together. Flexible couplings usually connect the pinion and gear shafts to the turbine and driven machine.

*S&V pages 58, 107*

# Chapter 19 Feedwater Heaters and Regenerative Feedwater Cycle

## 1. What is a regenerative cycle?

In the regenerative cycle, feedwater is passed through a series of feed-water heaters and is heated by steam extracted from stages of a steam turbine. This raises the feedwater to near the temperature of boiler water, thus increasing the thermal efficiency of the cycle.




*Typical fossil fuel power plant turbine-heater cycle.*

Figure 656.

In the regenerative cycle of feedwater heating, steam is bled from the turbine at one or more points and used to heat the boiler feedwater. The heat used in this fashion is returned to the boiler feedwater system, and the regenerative cycle shows a net gain in efficiency over the other methods of utilizing steam.

The heater acts as condenser of the bleed steam, and the amount of steam extracted is automatically balanced against the amount of feedwater entering and flowing thru the heater. As turbine load increases, steam flow through the turbine increases. This causes a pressure increase in respective turbine stage. Pressures resulting in an increase in bleed steam pressure and temperature to the feedwater heaters.

Usually temperature increases, however, due to the increased flow of water to carry the increased load. The effect of higher steam temperatures may be canceled out by increased water flow and thus outgoing temperature may not change.

*D.E.S.C. Steam Cycle page 13. D.E.S.C. Modern Turbines page 10*

## 2. What is a regenerative-cycle turbine?

A regenerative-cycle turbine is one where steam is taken from intermediate stages of the turbine to mix with the feedwater it heats as it heads back to the boiler. The steam pressure is determined by what stage it is piped to and the load on the turbine. The steam is not controlled by extraction valves and therefore the outlets are considered bleeds and not extractions.

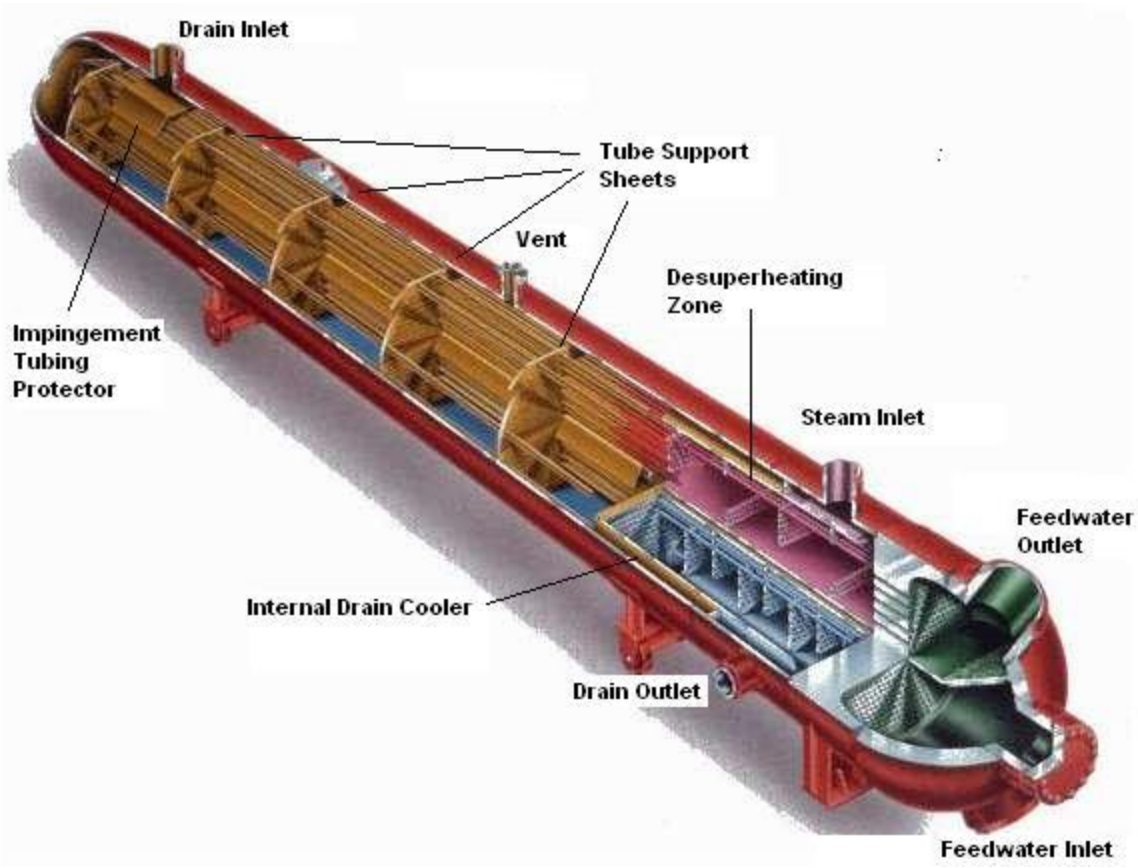



Figure 657. Feedwater heater construction

## 3. What benefits may be derived from a regenerative feedwater heating system?

A condensing turbine operating without a regenerative heating cycle rejects about 66% of the heat in the steam to the cooling water in the condenser. The use of staged feedwater heating reduces the amount of heat supplied to the boiler because less heat is rejected to the condenser. The steam has produced a certain amount of power in passing through the stages of the turbine, but still contains a great amount of heat. Bleeding off the steam at different points between the turbine inlet and exhaust for feedwater heating reduces the amount of steam flow and heat lost to the condenser, returning more heat to the steam-water cycle. The savings in heat consumption may be as high as 15%, depending on the steam pressure and number of heaters used. Higher feedwater temperatures also reduce the stress and strain on boilers. The amount of steam bled for feedwater heating is about 1% of the throttle flow for each 10 degrees F. rise in feedwater temperature, and at constant load, the flow to the throttle is increased about as much as the flow to the condenser is decreased.

*D.E.S.C. Turbine Operation and Maintenance. page 21*

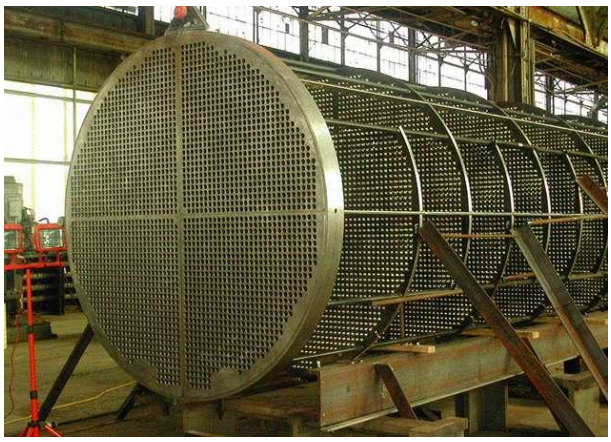


Figure 658. Feedwater heater tube sheets

Figure 659. Expanding tubes in the tube sheet

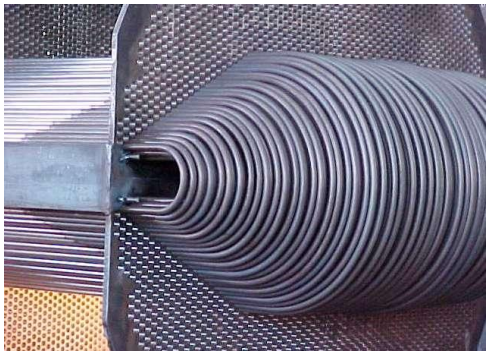


Figure 660. U-tubes partially installed in the tube sheets

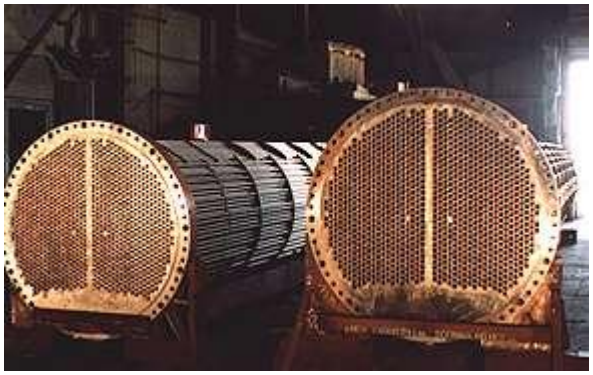


Figure 661. Tube bundles installed in the tube sheets

Figure 662. Completed tube bundles viewed from the rear

Figure 663. Completed tube bundle with impingement covers

## 4. If water temperature going to the closed feedwater heater rises, what happens to the excess steam from the auxiliary bleed line?

The pressure and thus the temperature of the steam in the closed feedwater heater is the same as that of the stage at which the bleed point is attached.

The amount of steam that flows to the heater depends on how much is condensed in the closed heater. As water temperature increases less steam is condensed and bled off. The rest of the steam is routed through the turbine to the condenser.

*Combustion Engineering Blue Cover page 13-7*

Figure 664. Feedwater heater under insulation

Figure 665. Feedwater heater with sightglass

Figure 666. feedwater heater sightglass

## 5. What is the relationship between the total amount of condensate leaving the condenser hotwell of a straight cascading regenerative cycle turbine and the throttle steam flow?

Total condensate leaving the condenser hotwell should equal the steam entering turbine throttle if all condensate flows back to the condenser hotwell before heading back to the boiler.

*S&V page 202*

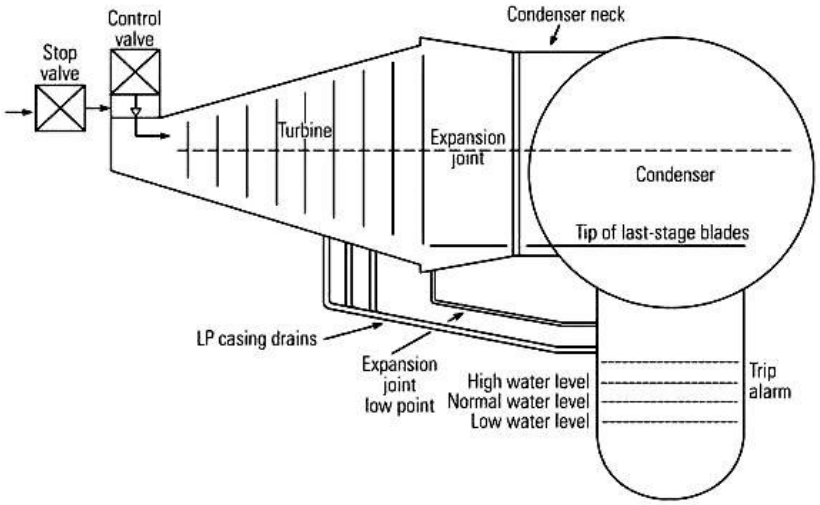



Figure 667. If there were no leaks and losses, all condensate would equal the steam entering the turbine

Steam enters the condenser where it cools and condenses into water before being sent to the low-pressure feed-water heater. The condenser hotwell serves as a water reservoir for the turbine cycle. When hotwell level reaches the low point, a valve opens to supply make-up water to the cycle. When hotwell level reaches the high end of the level range, a dump valve opens to move the condensate from the hotwell to a condensate storage tank.

## 6. What controls the water level in the feedwater heater?

Float switches open valves that allow the condensate to flow back to the next lower pressure heater

Figure 668. Feedwater heater float switch

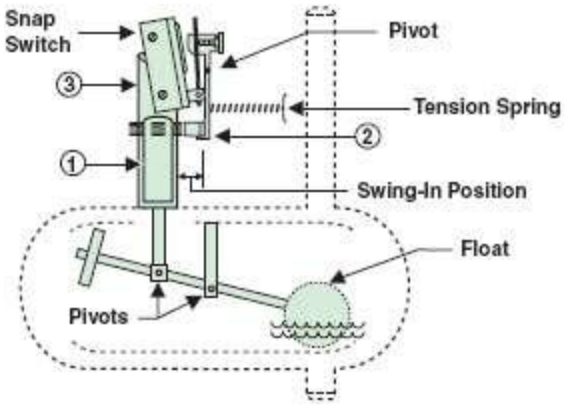
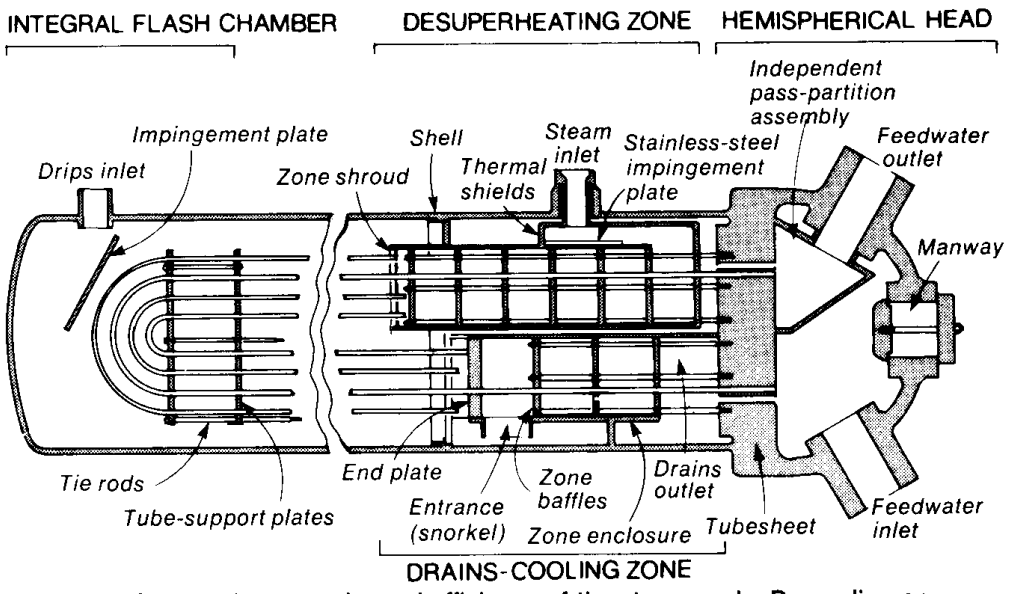



Figure 669. Internal construction of feedwater float switch




**Feedwater heaters** increase thermal efficiency of the steam cycle. Depending on station size and type, a dozen or more heaters may be installed in a modern plant

Figure 670. Internal construction of a feedwater heater

Figure 671. Large feedwater heater ready for shipment on a flatbed trailer.

# Chapter 20 Extraction Valves and Extraction Trips

## 1. What are extraction-pressure control valves?

Extraction-pressure control valves regulate the steam flow from the chamber into the following turbine stages, so that the steam pressure in the chamber and hence, in the extraction lines, remains constant.

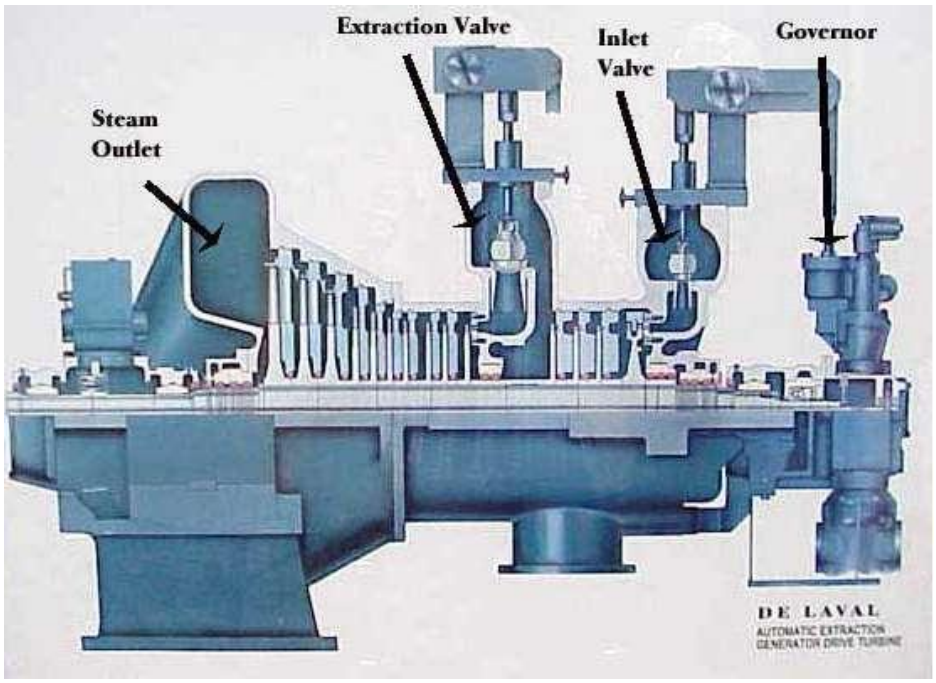



Figure 672. DeLaval Extraction turbine

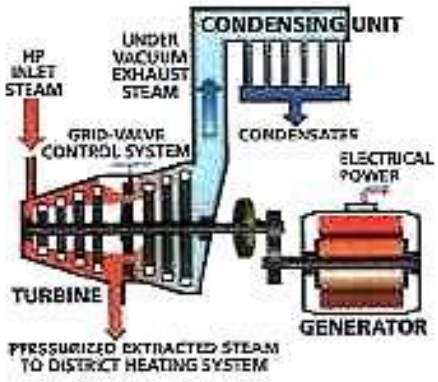



Figure 673. A city can use extracted steam to heat downtown office buildings which is the main purpose of the steam. Excess steam is used to generate electricity

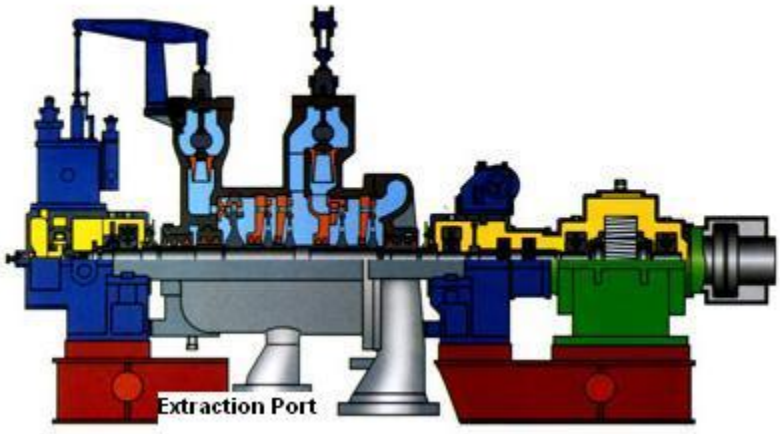



Figure 674. Showing the extraction valve and the extraction port

## 2. What keeps condensate from backing up from the feedwater heater and flooding the turbine?

A balanced check valve is always installed between the turbine and the heater and is usually preceded by a shut-off gate valve.

*D.E.S.C. Steam Cycle page 23*

A check valve and extraction trip is always installed between the feedwater heater and the turbine to prevent condensate from backing up into the turbine.

Figure 675. Gimpel extraction trip

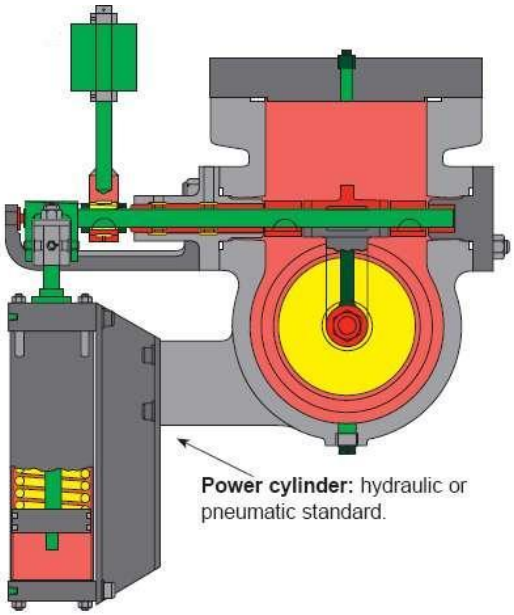



Figure 676. Schematic view of extraction trip valve

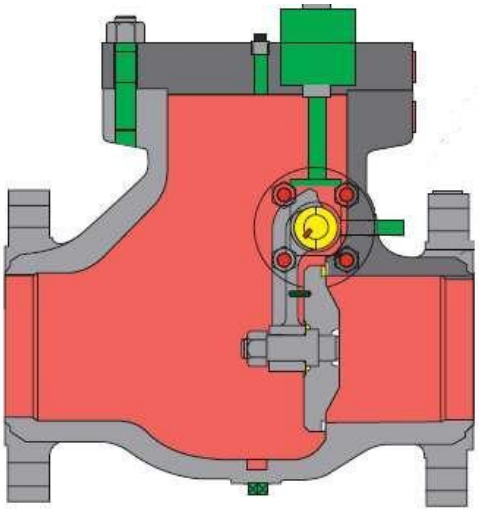


Figure 677. side view of Gimpel extraction trip valve

Figure 678. Another brand of extraction trip valve

This extraction trip valve on the Detroit Exam is referred to as an Atwood Morrill valve, after the name of the manufacturer. Referring to the extraction trip as an Atwood Morrill is used to confuse people on the oral exam.

*George Brown. Shift Engineer. Mistersky Power Station.*

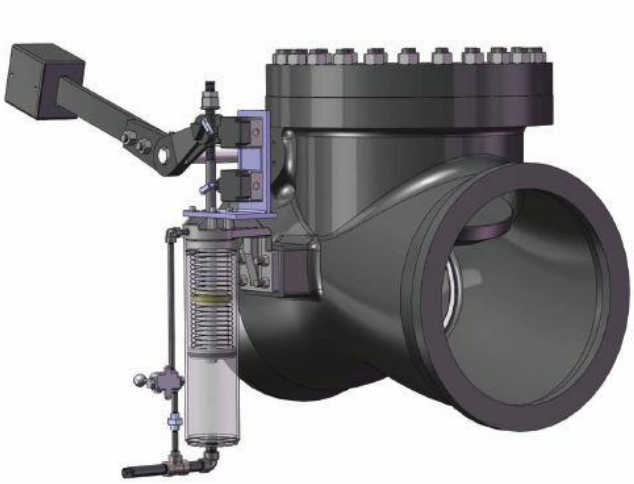


Figure 679. Atwood Morrill extraction trip

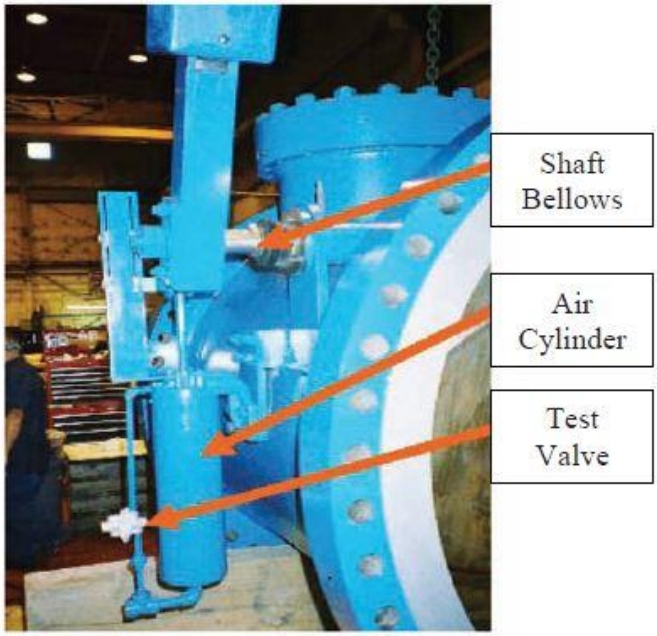



Figure 680. Air cylinder actuator of Atwood Morrill valve

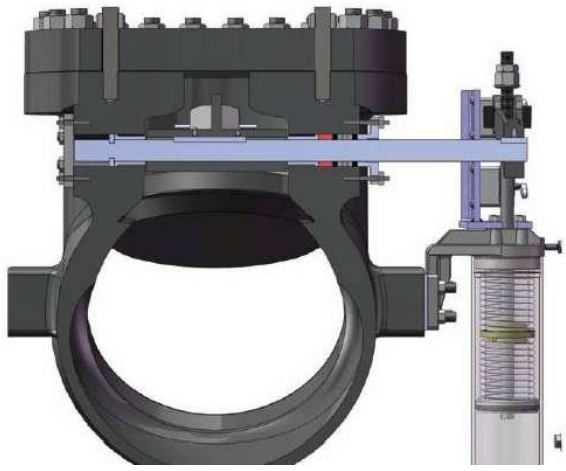


Figure 681. Air cylinder and pivot linkage

Figure 682. Back side of the actuator of the Atwood Morrill extraction trip valve

## 3. What happens if the check valve leaks?

If the check valve leaked by then the extraction trip valve would already be closed. These valves are located on the line from the turbine to the heaters. They are held open by control air (30 PSI). If water level in the heater rises too high, then the air is bled off the valves and they close. Normal water level in feedwater heater is 1/2 full. A regulator in the water drain lines controls the water level in the heater's upstream. There are high and low water level sensors in the heaters. The first heater after the feed pump is dry.

*Joe Grubbs Class Notes*

## 4. What happens on an extraction trip?

Extraction valves in the bleed or extraction line between the turbine and the feedwater heater close in response to a signal sent by a water level sensor located in the feedwater heater.

This valve prevents damage to the turbine by water should the level in the heater become too high. High water level in the heater could be caused by a ruptured tube or a trap that does not drain properly. A check valve is also provided in the bleed line to protect the turbine.

This extraction trip valve is located in the bleed line between the turbine and the closed heater. It is held open by control air pressure. When high water level is sensed in feedwater heater, air pressure is bled off, and the valve closes. This prevents water backing up into the turbine and causing damage to turbine blading. A check valve and stop valve are also provided in the bleed line to the heater.

*Joe Grubb*

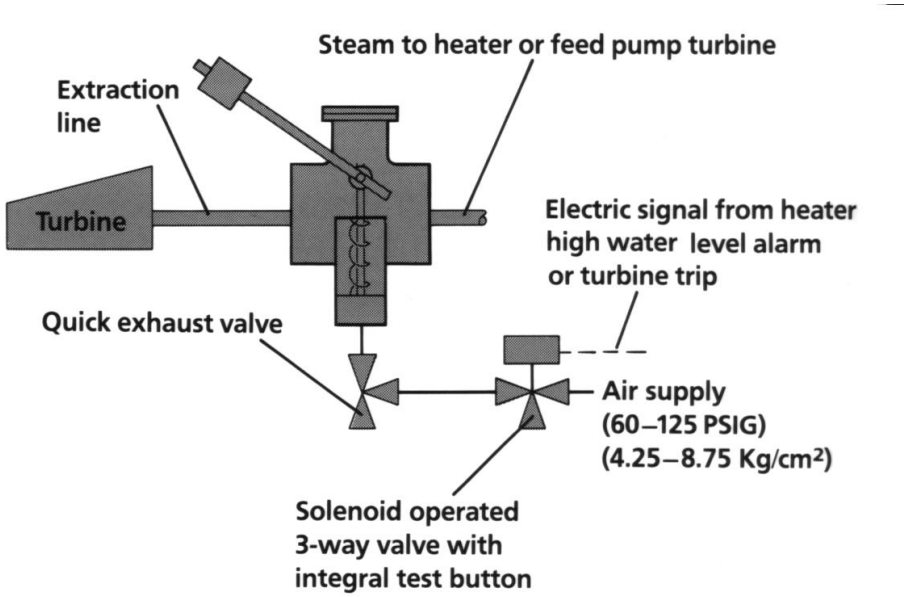

Steam to heater or feed pump turbine
Extraction line
Turbine
Electric signal from heater high water level alarm or turbine trip
Quick exhaust valve
Air supply (60–125 PSIG) (4.25–8.75 Kg/cm²)
Solenoid operated 3-way valve with integral test button

Figure 683. Showing controls that operate the extraction trip valve

## 5. Explain the purpose of the grid on the extraction turbine.

The steam drawn from an extraction turbine is at constant pressure, regardless of the amount of steam entering the turbine. This is accomplished through the use of an extraction valve. This valve is usually of the grid type. Grid valves make good extraction valves because very little movement is required to open and fully close the valve. The control of the valve is a function of extraction pressure and not of the governor. For this reason the pilot valve is operated by the extraction pressure; and the action of the pilot is relayed to the grid valve by use of the power piston. The valve is located in the turbine after the extraction opening. As the pressure in the extraction steam increases, the grid valve will start to open to reduce the amount of steam flowing to the extraction line.

*D.E.S.C. Modern Turbines page 14, Croft Steam Turbines page 198*

Figure 684. Grid valve location inside the turbine

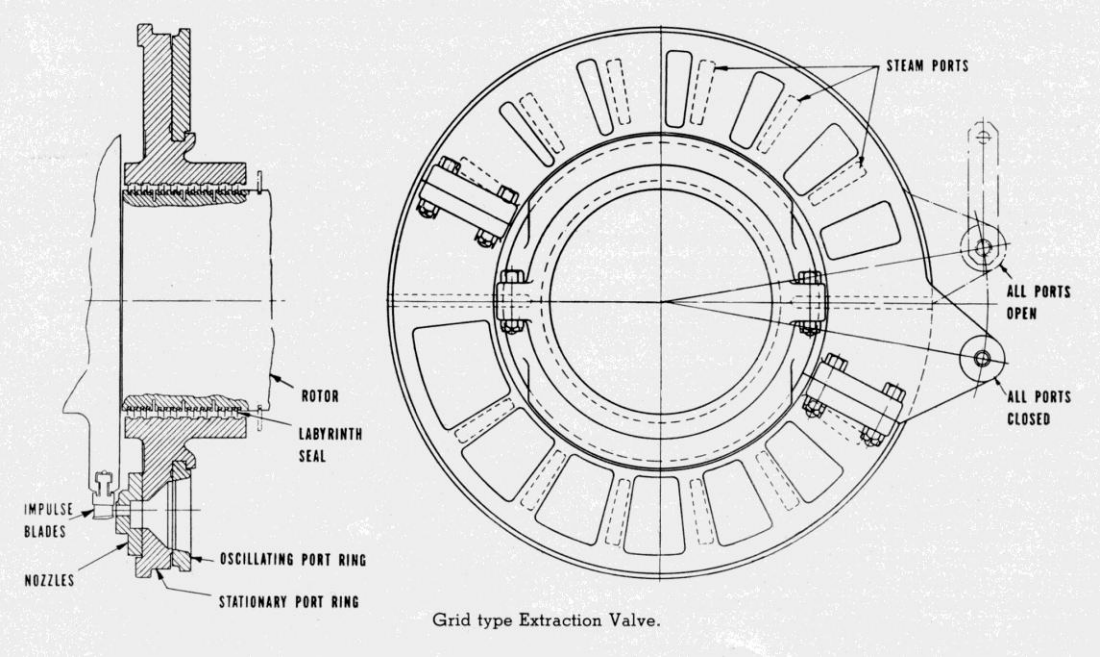



Figure 685. Grid valve diagram showing how the grid moves around the center to uncover the ports

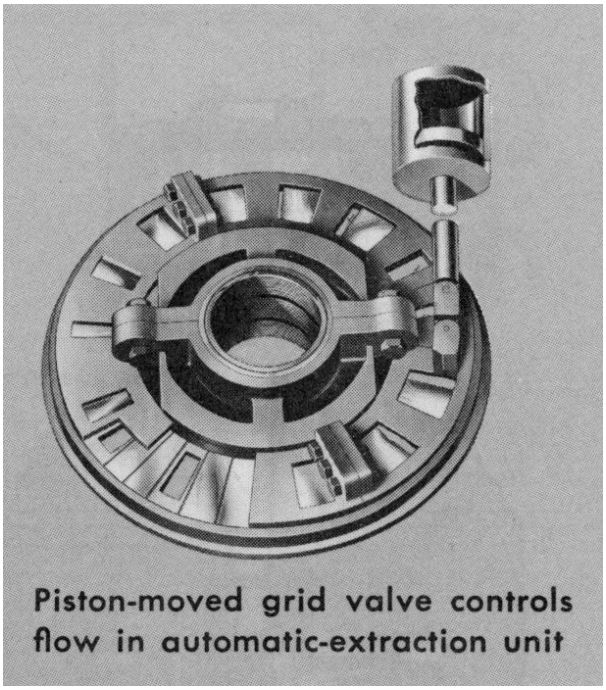



Figure 686.

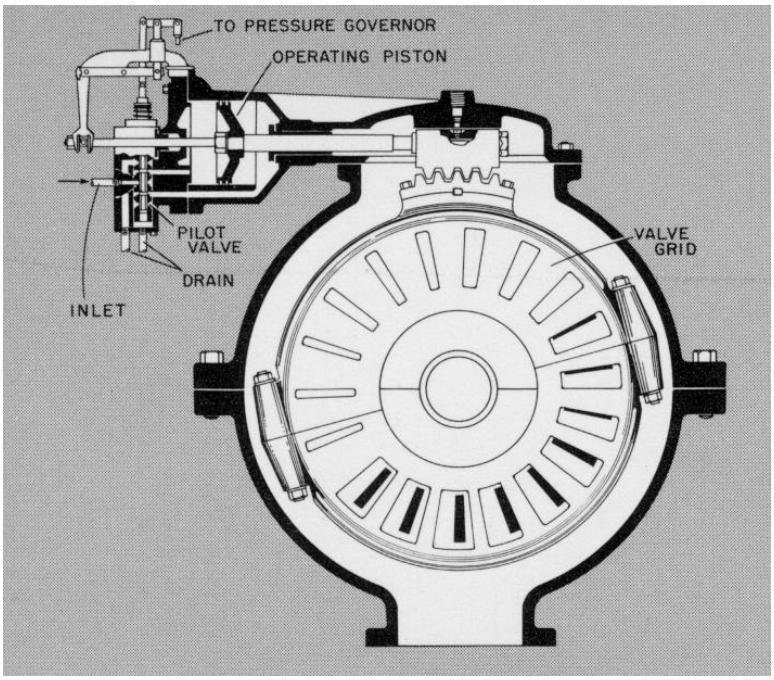



Figure 687. Shows the rack gear that moves the grid valve around the center axis

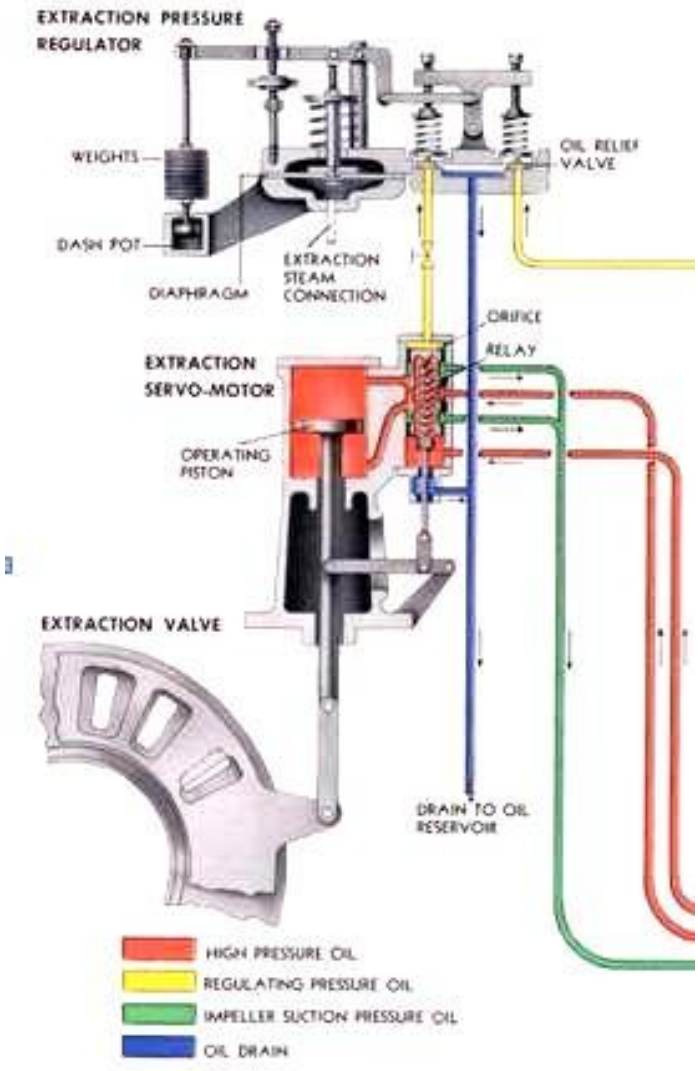



Figure 688. Oil operated extraction pressure regulator

Figure 689. Grid valve on turbine shaft

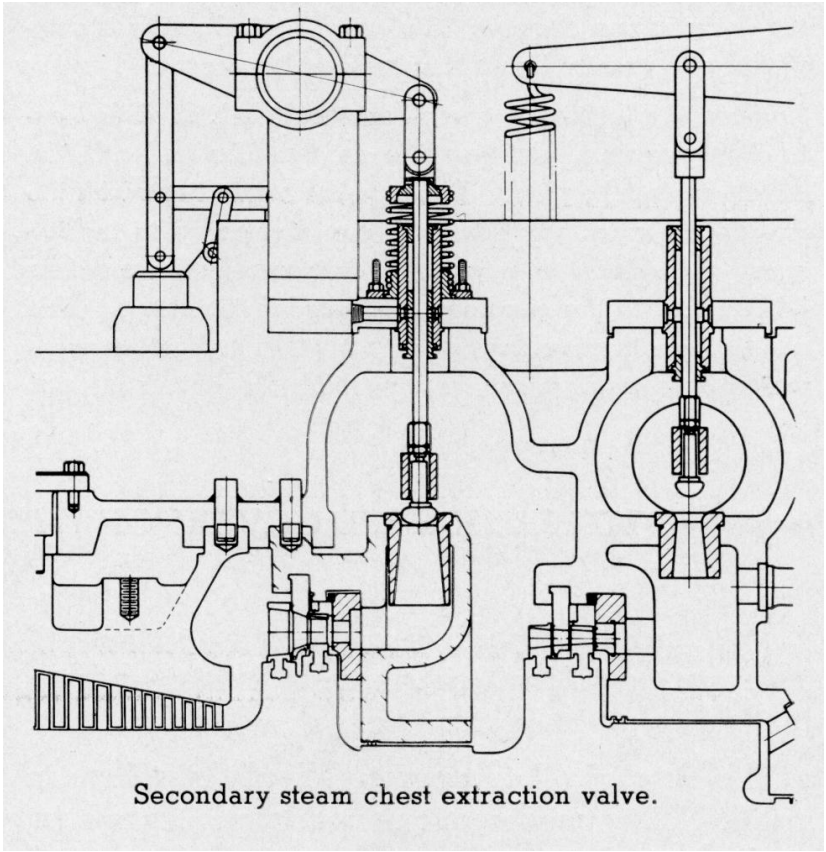



Figure 690. Using poppet valves instead of grid valves to control extraction pressure

## 6. Does the extraction valve ever completely close?

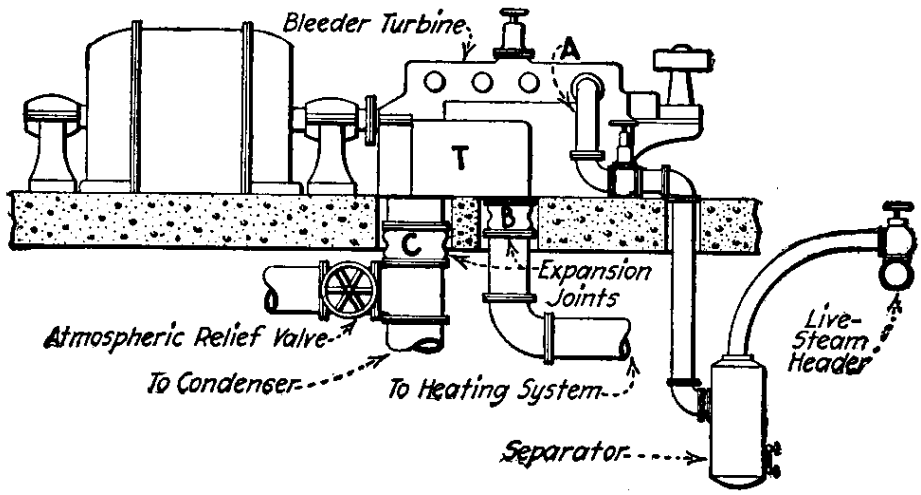
A certain amount of steam in an extraction turbine must pass through to the exhaust to keep the exhaust hood cool. If all steam were to go out the extraction port, the exhaust hood would overheat. The grid valve is located after the extraction port and never goes completely closed.

## 7. What is the difference between the bleeder turbine and the extraction turbine?

Bleeding steam refers to the withdrawal of relatively small amounts of steam, without pressure control for heating or process work outside the turbine. As the load on the turbine increases, the steam flow through the turbine increases. This causes an increase in bleed steam pressure to the various processes.

The steam drawn from the extraction turbine is at constant pressure regardless of the amount of steam entering the turbine. This is accomplished through the use of an extraction valve located in the turbine casing. It will open to pass steam through the turbine on an increase in extraction steam pressure and close off to force more steam through the extraction point on a decrease in extraction pressure. Steam temperature in the extraction line to the process for which it is used is a function of the steam pressure. For this reason extraction turbines can be used to effectively control process temperature and pressure while extracting a certain amount of work from the steam in the turbine before use.

*D.E.S.C. Modern Turbines page 10, Croft Steam Turbines page 198*




**A bleeder turbine installed to supply a low-pressure main with steam and condense the exhaust which is not needed for heating.**

Figure 691.

# Chapter 21 Condensers

## 1. How is exhaust steam from the turbine handled?

The exhaust steam is collected in the exhaust hood where it is then delivered to the condenser in condensing plants or to the exhaust pipe in noncondensing plants. The condenser is usually fastened directly to the turbine exhaust hood.

*D.E.S.C. Simple Turbines page 3*

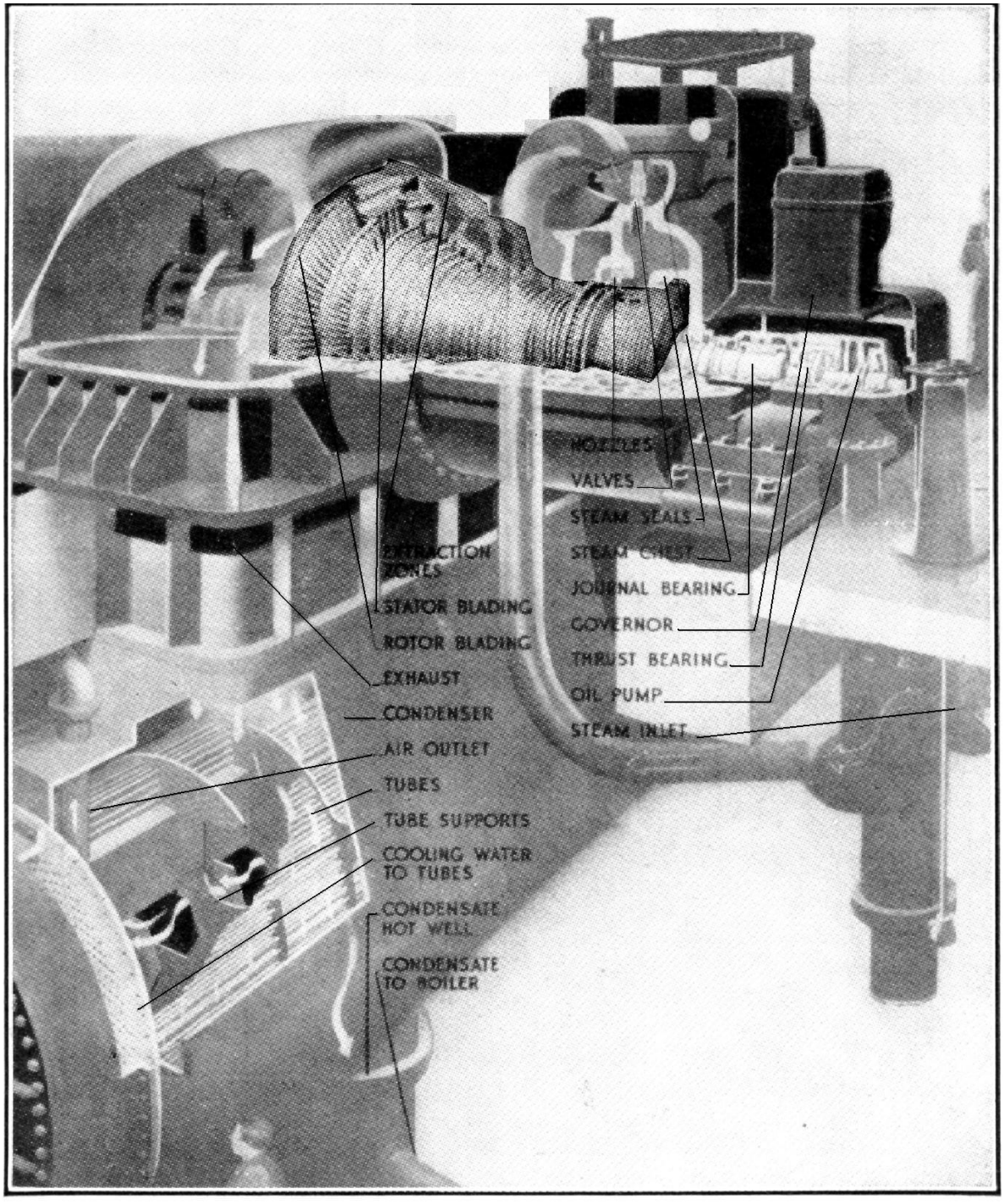



Figure 692. Phantom view of turbine and condenser

## 2. What is a steam condenser?

It is a heat exchanger wherein steam is condensed either in direct contact with cooling water or indirect contact with cooling water through a heat transfer medium separating them.

That is, a steam condenser is either a direct contact or indirect contact heat exchanger.

A condenser is a device that converts a vapor to a liquid by removing heat from the vapor.

A pound of steam does as much work when expanding from atmospheric pressure to a vacuum of 29" hg. as it does when expanding from 200 PSI at 600 F. to atmospheric pressure. Thus, when a turbine discharges to a condenser the horsepower and the efficiency of the unit is increased.

There are two (2) general classifications of condensers.

1. Surface, where water and steam do not come into direct contact.

    a) Shell and coil

    b) Shell and tube.

2. Direct Contact, where steam and cooling water mix

    a) Barometric - uses 34 ft. to 35 ft. tail pipe.

    b) Low Level Jet - uses a pump to remove condensate and water.

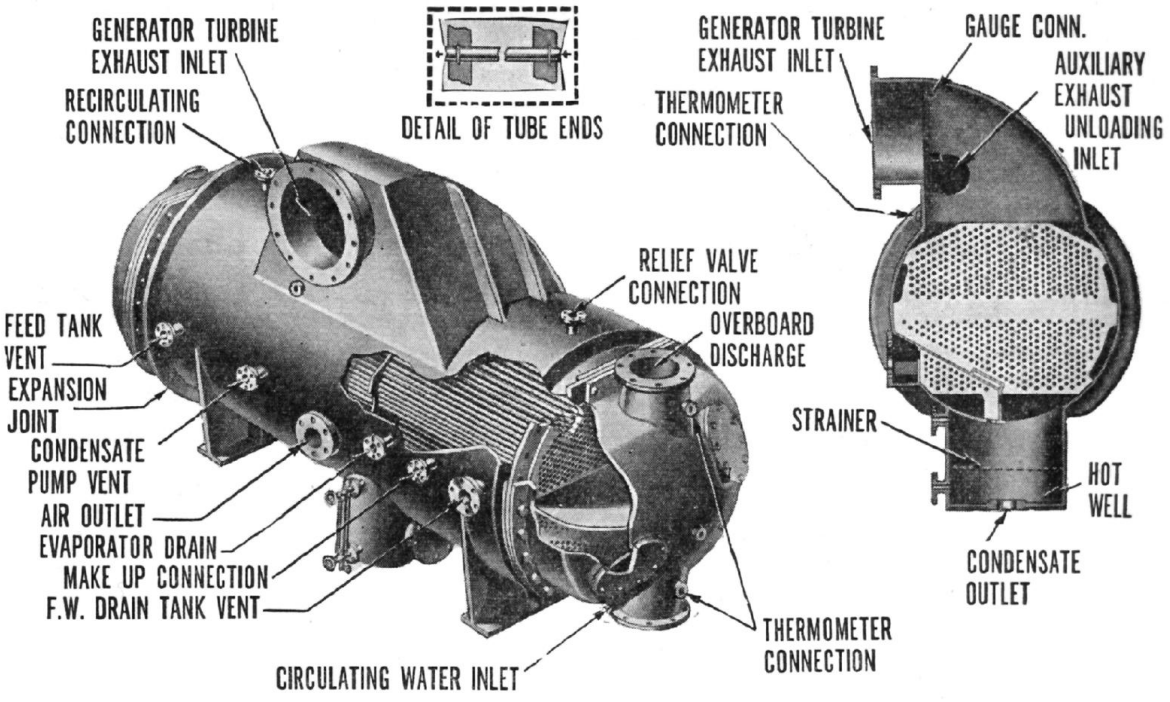



Figure 693. Detailed cutaway of shell and tube condenser

## 3. What is a waterworks condenser?

In surface condensers the steam is almost always on the shell and water is in the tubes. The exception is the waterworks type which is the opposite. In waterworks service where an abundance of cool water is always available, the surface condenser is frequently built into the suction or discharge pipe of a large pump. The condenser then differs from the regular type in that the cooling water flows around the tubes and the exhaust steam is condensed inside the tubes, the object being to provide ample passage for the water.

In designing a waterworks condenser, care must be taken to keep the water openings clear and allow ample waterway around the tubes

The recognized waterworks surface condenser construction calls for tube heads of composition and tubes of seamless drawn brass, untinned. These tubes pass through stuffing-boxes in both tube heads, which have threaded brass ferrules, each with a lip on the inside. This lip prevents the tubes from creeping, which is a result of the constant expansion and contraction of the tube and shell.

If the discharge pressure is moderate the condenser is preferably located in the cross-discharge pipe. Although it will be more costly here, on account of heavier construction, there will be the advantage of having no obstruction in the suction pipe, which is especially to be avoided if the suction lift is high. A further advantage is that the waterworks condenser is placed some distance above the floor line, which gives a good head on the wet vacuum pump. For the case of a suction condenser, this pump must necessarily be placed in a pit.

*D.E.S.C. Steam Condensers page 1, W. & L. page 466, Direct-acting steam pumps By Frank Ferdinand Nickel page 190*

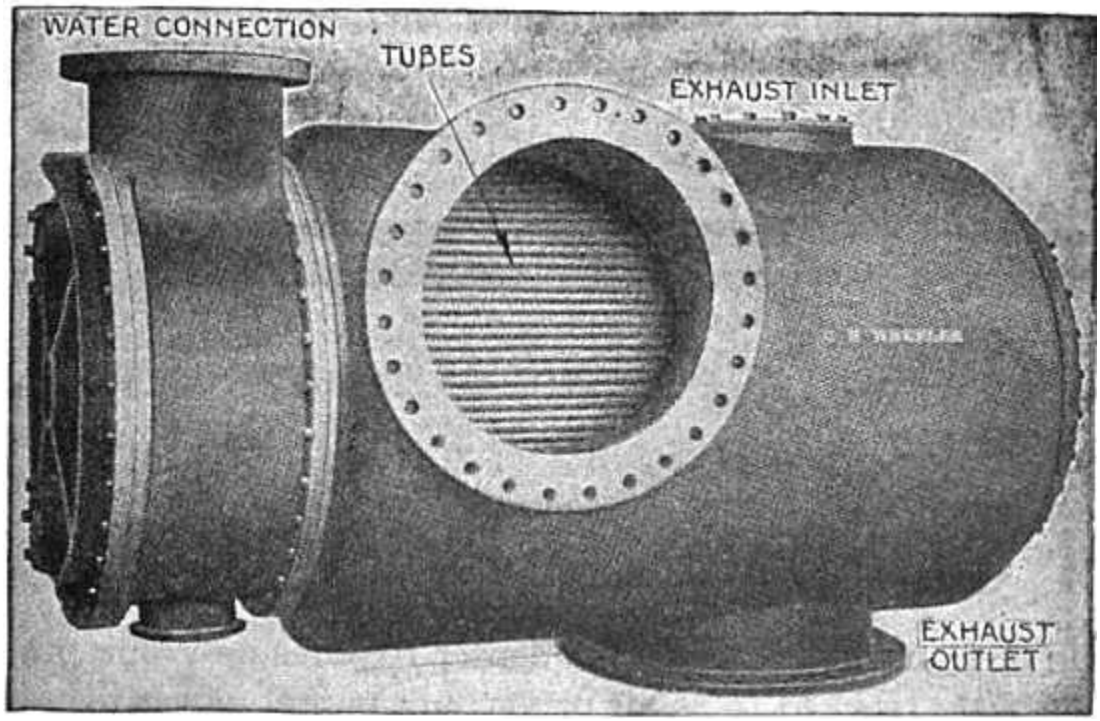



Figure 694. Waterworks Condenser

## 4. What are the primary functions of a condenser?

There are two important functions of a condenser:

1. It reduces the back pressure upon the turbine by a considerable degree and therefore, the work done per lb of steam during expansion is increased

2. The exhaust steam condensate can be recycled as boiler feedwater

## 5. What should be the basic criteria for an efficient steam condenser?

Maximum amount of steam condensed per unit area of available heat transfer surface.

Minimum quantity of circulating coolant required.

Minimum heat transfer surface required per kW capacity

Minimum power drawn by the auxiliaries

## 6. Name three types of condensers

Surface Condensers (shell-and-tube) - indirect contact heat exchanger using water.

Low Level Jet - direct contact heat exchanger.

Barometric Jet - direct contact heat exchanger

## 7. What are two other types of condensers that are not as common as the first three?

Air-cooled condenser

Evaporative condenser

Figure 695. Air cooled Condenser

Figure 696. Evaporative Condenser

## 8. What is a surface condenser?

It is a shell-and-tube heat exchanger in which steam is condensed on the shell-side while cooling water flows through the tubes. The condensate and cooling water leave the system separately.

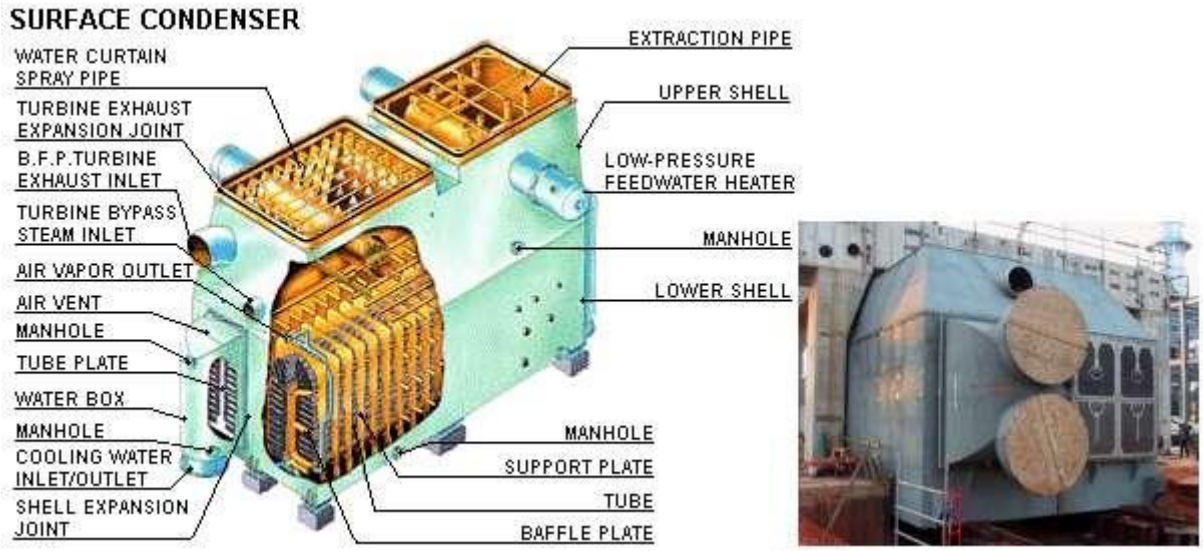



Figure 697. Cutaway view and outside view of a surface condenser

Figure 698. Surface condenser

## 9. What are the advantages of a surface condenser over a jet condenser?

It imparts to power generation plant a higher thermal efficiency.

The condensate can be reused as boiler feedwater.

Auxiliary power requirement is less than that of a jet condenser.

Less amount of air is carried to the boiler.

## 10. What are the limitations of a surface condenser?

It is very bulky and as such requires more floor space.

Its manufacturing, running and maintenance costs are high.

## 11. What should be the requirements of an ideal surface condenser used for steam power plants?

1.) Uniform distribution of exhaust steam throughout the heat transfer surface of the condenser.

2.) Absence of condensate subcooling.

3.) There should not be any leakage of air into the condenser.

4.) There should not be any tube leakage.

5.) The heat transfer surface in contact with cooling water must be free from any deposit as scaling reduces the efficiency of heat exchangers.

## 12. How does the evaporative condenser function?

Exhaust steam from the turbine is condensed inside the finned tubes as cooling water rains down from the top through the nozzles. A part of the cooling water in contact with the tube surface evaporates by drawing enthalpy from the steam, which upon losing its latent heat condenses and discharges out as condensate. They are used in areas where cooling water is scarce.

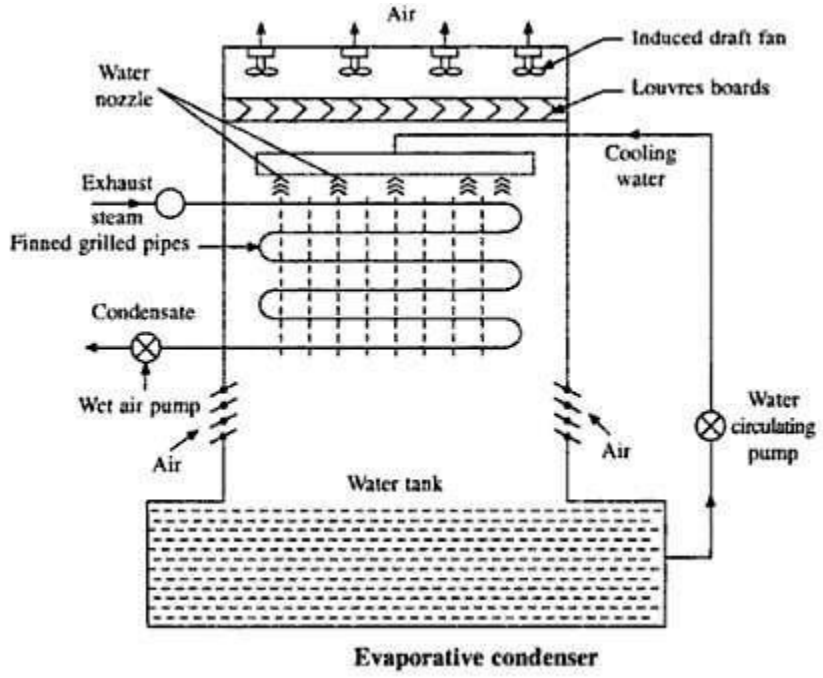
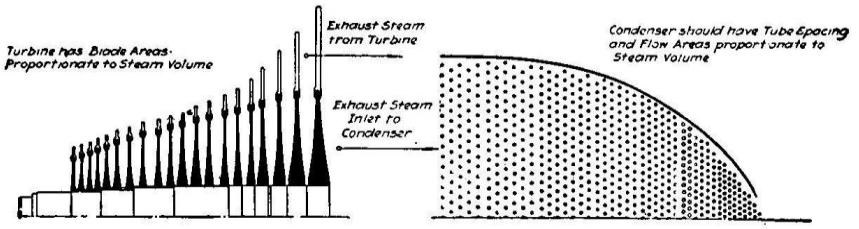



Figure 699. Evaporative condenser schematic

## 13. What is the steam lane of a surface condenser?

Steam lanes are passages in the surface condenser which allow steam to be evenly distributed to the lower portion of the condenser as well as the upper portion. This increases condenser efficiency and prevents the formation of dead air spots where non-condensables may collect. Steam lanes are formed by omitting tubes in the tube sheet. Steam lanes prevent subcooling of the condensate. The condensate should be as warm as possible when entering hot well. *McNaughton page 533*


Turbine has Blade Areas Proportionate to Steam Volume
Exhaust Steam from Turbine
Exhaust Steam Inlet to Condenser
Condenser should have Tube Spacing and Flow Areas proportionate to Steam Volume

The tube sheet is calculated with the same care as the blade areas of a steam turbine, as indicated above. The decreasing width of the condenser shell corresponds to the increasing diameter of the turbine wheels. The decreasing flow area between tubes brought about by a gradual reduction in the tube spacing corresponds to the increasing blade length. The area through any row of tubes or any turbine wheel is calculated to suit steam conditions existing at that point. (Ingersoll-Rand)

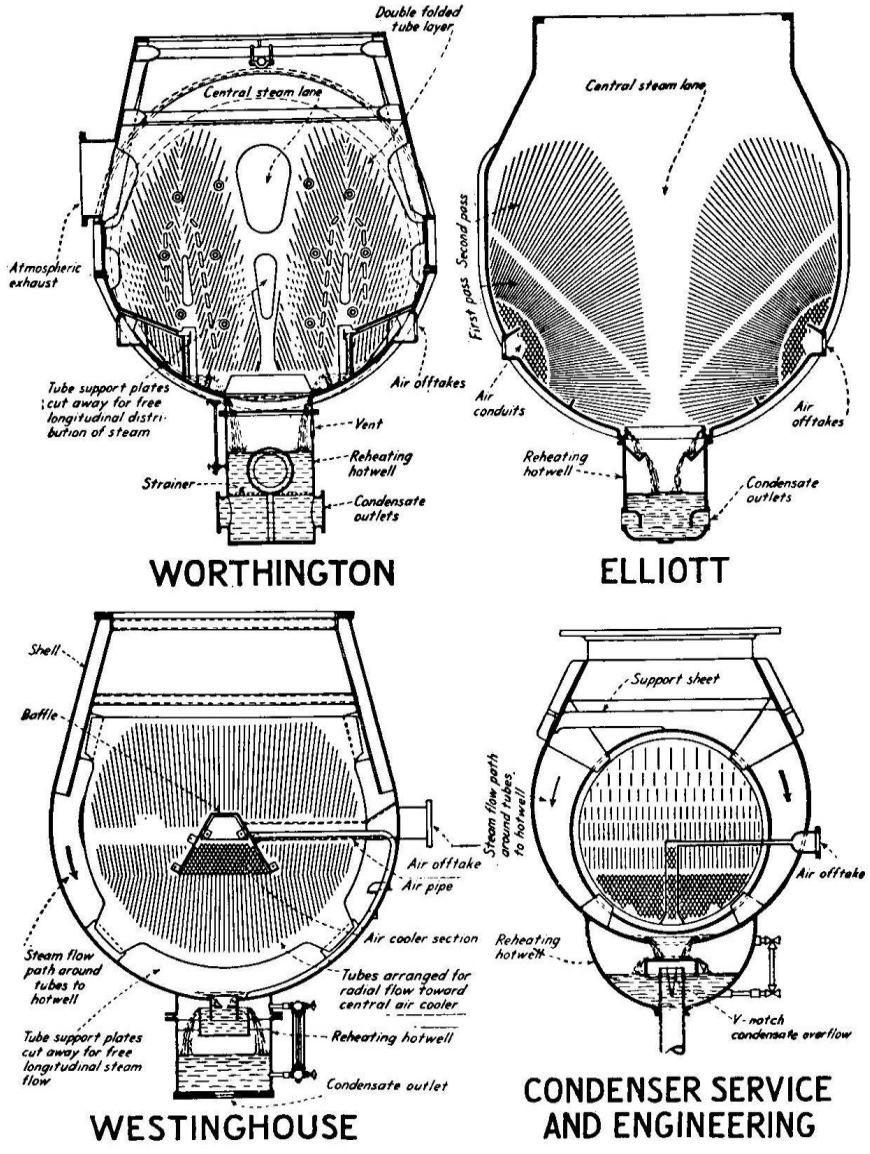



Figure 700.

Condenser cross sections. (Representative of large modern units.)

## 14. How do surface condenser insure a flow of steam over the full length of the tubes?

By the tube arrangement and the narrowing of the condenser vessel toward the bottom as steam is condensed. The tube arrangement has a decided effect and various layouts have become identified with certain companies. Passageways or lanes are provided through and around the outside of the tube nests. These lanes provide an effective flow path for the steam from inlet to exit lane and then to the air cooler. The air cooling system is internal, and the air offtakes removes the air-vapor mixture after passing the lower cooler tubes.

*Croft Auxiliaries and Accessories page 271*

## 15. What is a water screen for on a condenser?

A water screen is a device used to filter out foreign matter as plant life, floating wood, and fish. Water screens consist of two (2) chains traveling around a sprocket wheel at the head and foot. Foreign matter adheres to the surface of the screen and is dumped on the down run into troughs. The screens are sprayed with high pressure water jets to clean them during operation.

*Gephardt Power Plant Engineering page 557*

*Grubb's Notes Condenser Section (Drawing)*

Figure 701. Zebra Mussel

Figure 702. Zebra Mussel colony

Figure 703. Zebra Mussels on cooling water intake grate

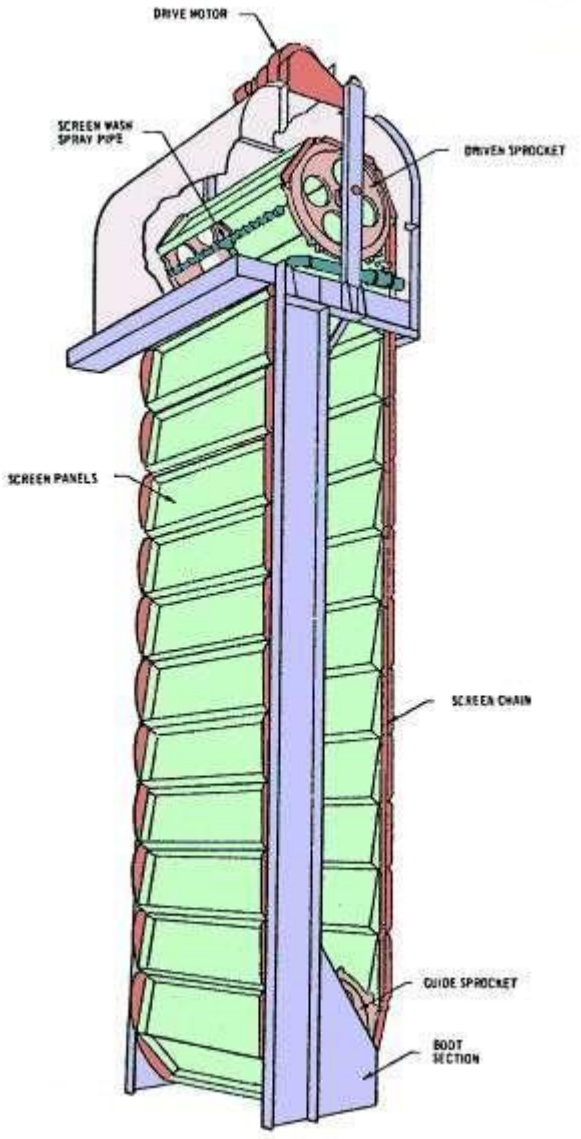



Figure 704. Travelling intake screen

**16. What are zebra mussels and how are they handled?**

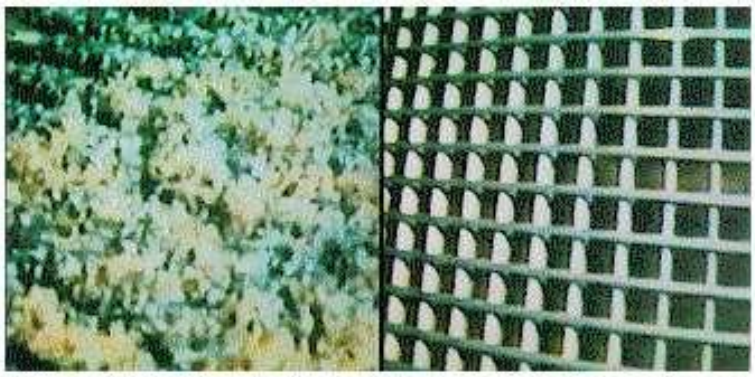
Zebra Mussels are freshwater mollusks the size of a fingernail and have a cream colored shell with dark brown bands. The shells zebra-like pattern led to the mollusks name. They firmly attach themselves to solid underwater surfaces, the only such freshwater mollusks to do so. Zebra mussels feed on floating plants and plankton by filtering water through their body. They quickly develop into colonies of hundreds of thousands per square yard clogging water intake pipes. High flow rates around water intakes make ideal locations for the mussels to feed. The cluster colonies can completely cover any submerged object quickly. Many divers upon a return engagement to a sunken shipwreck a year later have found the vessel completely covered with mussels and unrecognizable

By 1991, zebra mussels had spread to virtually all the Great Lakes and presently they have been found in several dozen lakes in the surrounding states most frequently in Wisconsin and Michigan. Lakes in Ohio, Illinois and Indiana have infestations. The zebra mussel population has risen dramatically in the upper Mississippi River and have now found their way into the Tennessee River.

The life span of the Zebra Mussel is between three and six years. They generally grow to less than an inch but can develop up to two inches long. The mussels have a high reproduction rate and a mature female can produce 40,000 eggs in one season. Microscopic larvae called veligers hatch from the fertilized eggs within a few days in waters with temperatures exceeding 55° F. The free swimming veligers are carried by water currents which allows for the rapid dispersment and is the most effective distribution of the organism. The veligers float in the water approximately 8 to 14 days before they must attach themselves to a solid object or die. Threadlike filaments are produced by the veligers and used to attach firmly to surfaces. Once attached to a surface they develop a double-shell within three weeks. The zebra mussels mature and are able to reproduce within a year.

Processes such as ozonation, ultraviolet radiation, electrical shock and sonic vibrations are still experimental. Because zebra mussels cannot survive in temperatures over 100° F, heat is an effective control method.

At Detroit Edison, hoses automatically deliver high pressure water every eight hours to dislodge the accretions from intake screens. "We also use very hot water to kill zebra mussels at our small plant in northern Michigan," Another problem caused by the mussels is that they eat so much plankton, it clears the murkiness of the water, so that the sun's light penetrates deeper, stimulating heavy growth of weeds. The weeds also clog intakes.



These underwater photos compare screens over adjacent underwater intakes at a Consumers Power Company station in West Olive, Michigan. The stainless steel screen (left) is completely clogged with zebra mussels. The biostatic copper alloy screen (right) is almost completely free of mussels. It was fabricated by Wheelabrator.

Figure 705.

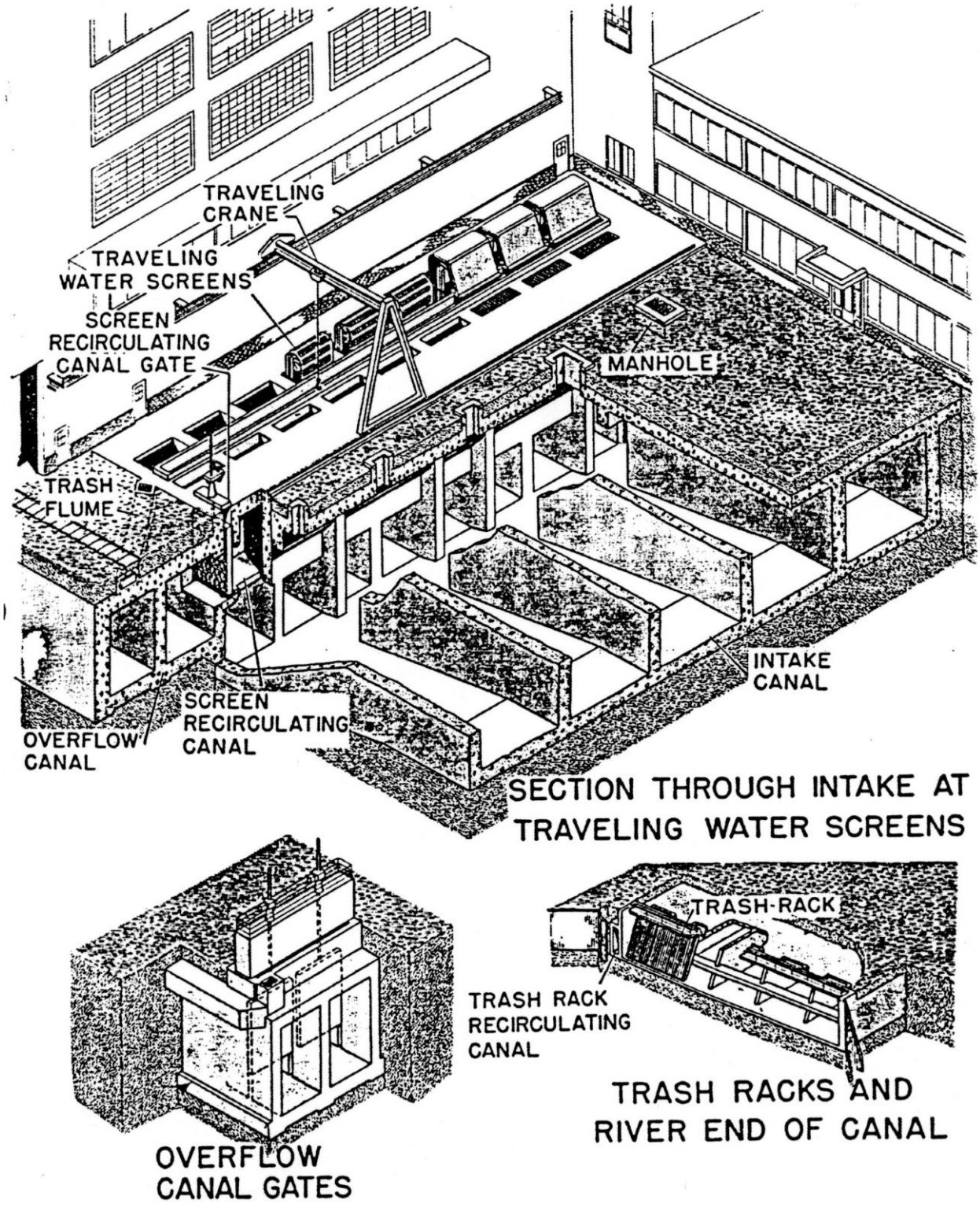



Figure 706. Water intake system at a large powerplant

## 17. Why must condensate be subjected to salinity tests where brackish cooling water is used?

Condensate may leak from the cooling-water side to the steam side of the condenser and contaminate the feedwater, thus causing scale to form in the boilers. Or brackish cooling water may leak into the steam space from cracked or porous tubes or from around the joints at the end of the tube ends, etc. By taking salinity readings of the condensate, leaks may be found before they can do any harm.

## 18. How would you stop a leaky tube in a condenser that was contaminating the feedwater?

To stop a leaky tube from contaminating the feedwater, shut down, remove the water-box covers, and fill the steam space with water. By observing the tube ends you can find the leaky tube. An alternate method is to put a few pounds of air pressure in the steam space, flood the water boxes to the top inspection plate, and observe any air bubbles. Once you have found the leaky tube, drive a tapered bronze plug (coated with white lead) into each end of the tube to cut it out of service. This allows you to use the condenser since the tubes need not be renewed until about 10 percent of the tubes are plugged.

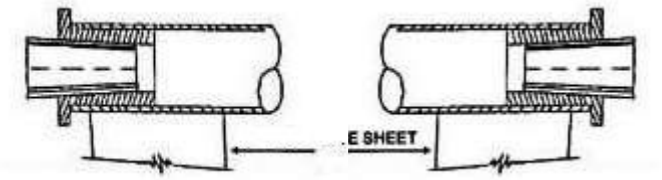



Figure 707. Plugged ends of a condenser tube sheet

Figure 708. Brass plugs. The type 2 plug has a collar that is inserted into the tube first and then the plug is expanded into it

Figure 709. Brass plug for plugging leaking tube end

Figure 710. Pounding in the brass plug

## 19. Do you stop cooling-water flow through a steam condenser as soon as the turbine is stopped?

You should keep the cooling water circulating for about 15 minutes or more so that the condenser has a chance to cool down gradually and evenly. Be sure to have cooling water flowing through the condenser before starting up in order to prevent live steam from entering the condenser unless it is cooled. Overheating can cause severe leaks and other headaches.

## 20. Is zinc a satisfactory material for condenser tubes?

Yes

Where fresh water is used the tubes may be of brass, bronze, copper, aluminum bronze, or Muntz metal. Where salt water is used, tubes made of admiralty metal are preferred. This is an alloy containing 70 percent copper, 29 percent zinc and 1 percent tin. The tube sheets are generally made of brass or Muntz metal.

*Croft Auxiliaries and Accessories pages 380,381*

## 21. What is submergence in a condenser?

The distance from the top of the water level in the hotwell to the centerline of the condensate pump.

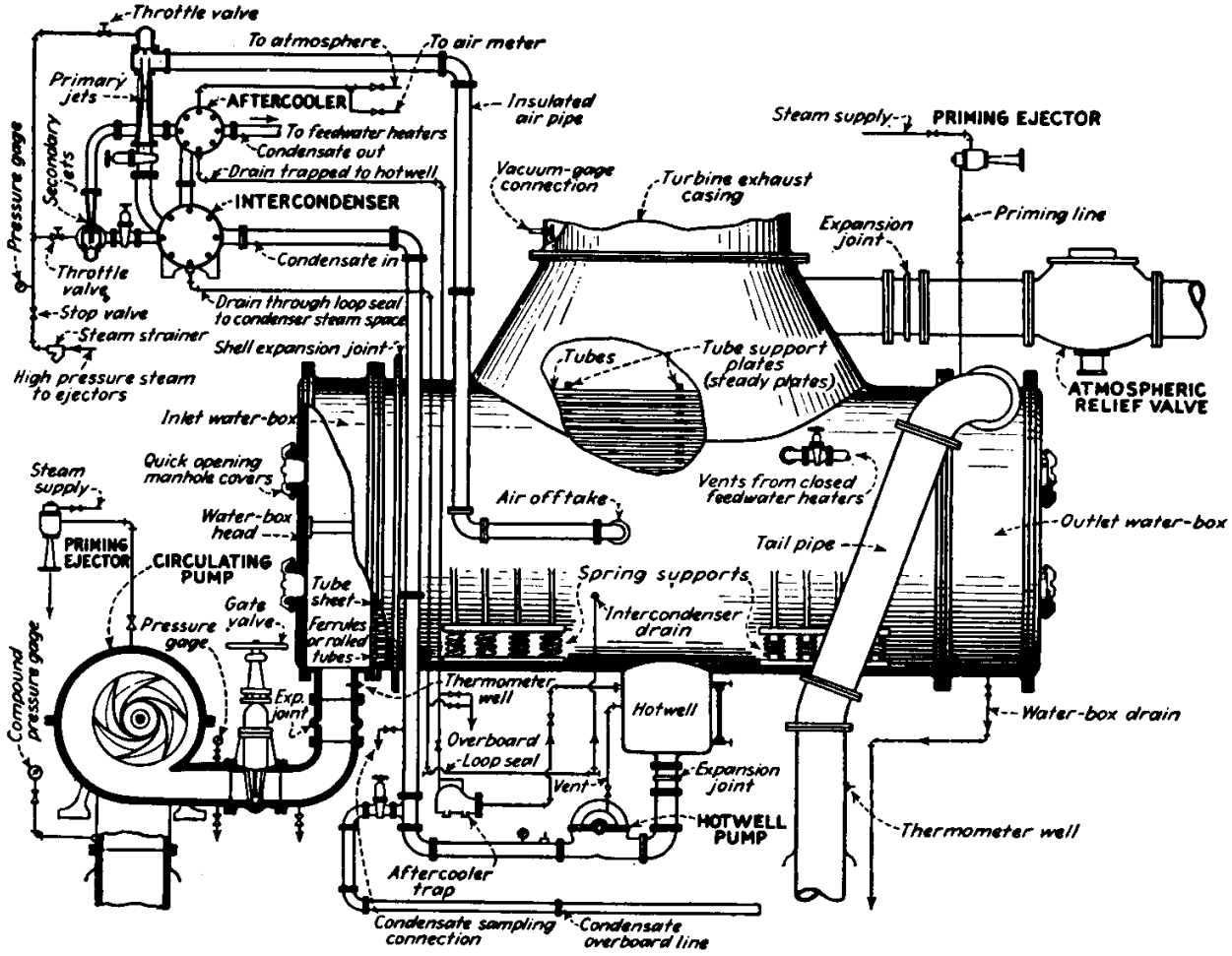
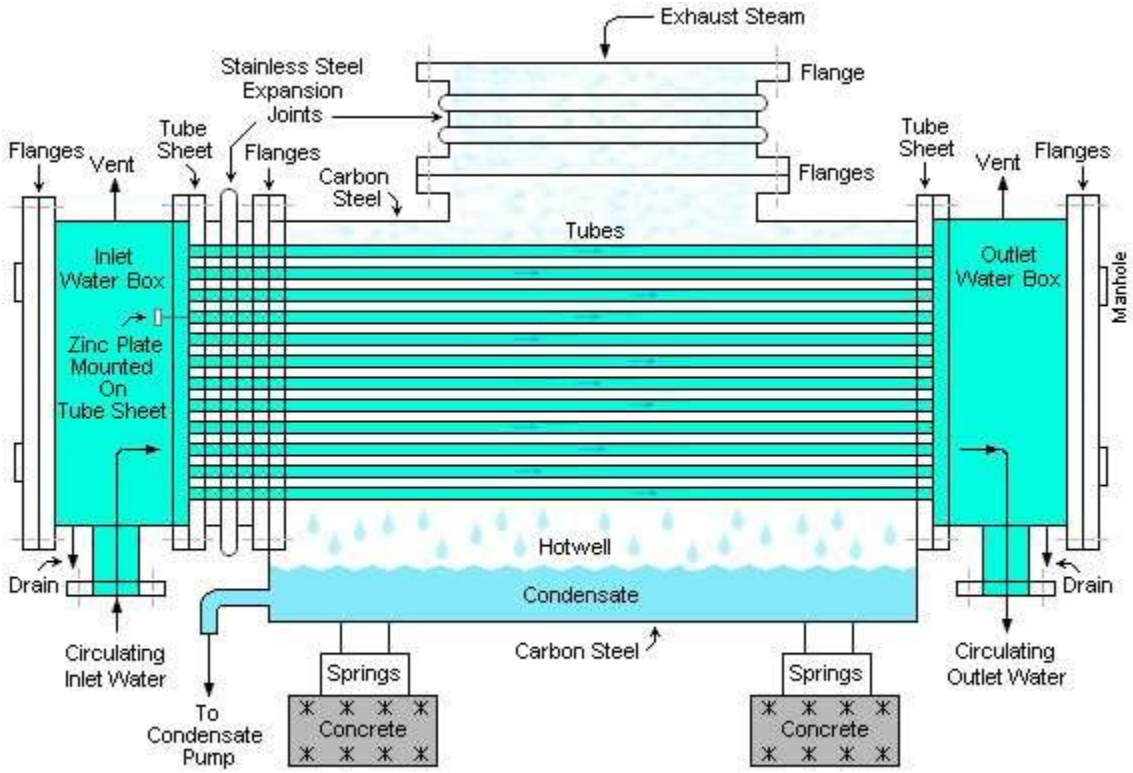



Figure 711. Diagrammatic view of modern condenser installation.

## 22. What are some common troubles in surface-condenser operation?

The greatest headache to the operator is loss of vacuum caused by air leaking into the surface condenser through the joints or packing glands. Another trouble spot is cooling water leaking into the steam space through the ends of the tubes or through tiny holes in the tubes. The tubes may also become plugged with mud, shells, debris, slime, or algae, thus cutting down on the cooling-water supply, or the tubes may get coated with lube oil from the reciprocating machinery. Corrosion and dezincification of the tube metal are common surface-condenser troubles. Corrosion may be uniform, or it may occur in small holes or pits. Dezincification changes the nature of the metal and causes it to become brittle and weak.




Note: Tubes are brass, cupro nickel, titanium or stainless steel. The tubes are expanded or rolled and bell mouthed at the ends in the tubesheets.

Figure 712. Surface condenser diagram

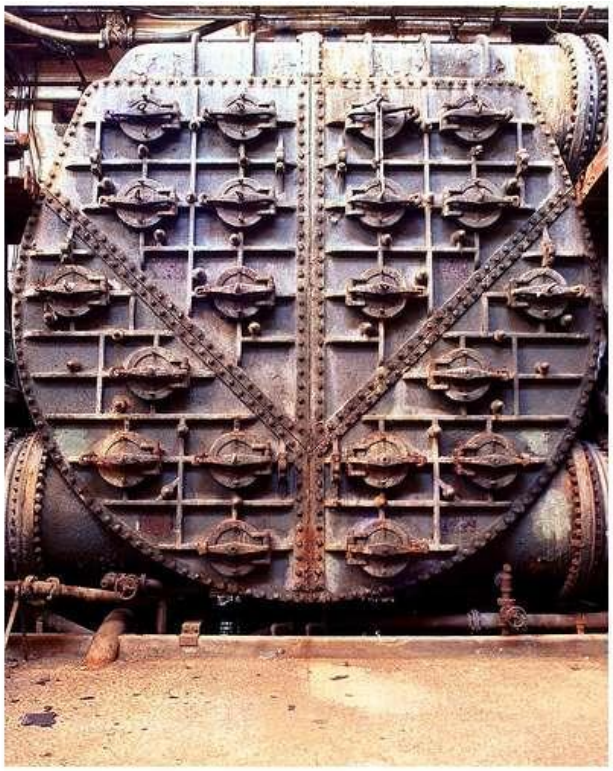


Figure 713. Each one of these hatches is large enough for a man to enter

# Jet Condensers

## 23. What is a jet condenser?

It is a direct contact heat exchanger in which steam to be condensed comes into direct contact with the cooling water (cold condensate) which is usually introduced in the form of a spray from a jet.

Upon contact with the cooling water, the steam gives up its enthalpy and gets cooled and ultimately settles as condensate.

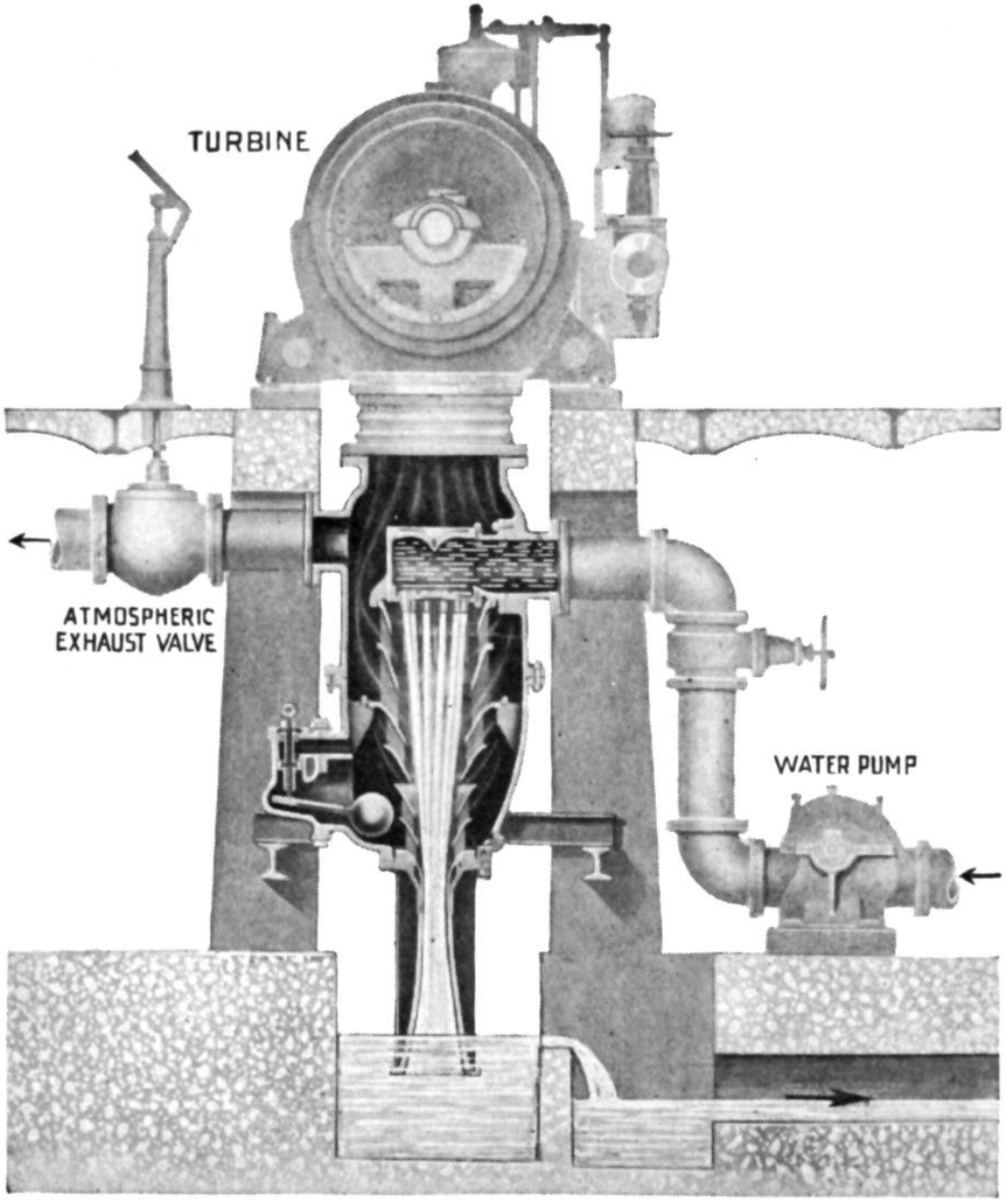



Figure 714. Koerting low-level multi-jet ejector condenser under a steam turbine.

## 24. What is the difference between a jet condenser and a surface condenser?

In the jet condenser the circulating water and the steam mix physically. The effect is to condense the steam while the circulating water rises slightly in temperature.

Since steam is steadily exhausted to the condenser and water steadily supplied, a low constant pressure condition is produced within the condenser. For such operation there must also be a constant removal of condensed steam together with the water in which it is mixed. This type of condenser can use fairly dirty condensing water, is cheaper, and in general requires less maintenance and cooling water than the surface condenser.

The surface condenser is used in power plants to produce low back pressures or high vacuums for turbine exhaust. Compared to direct-contact type of condenser it has the advantage of being able to recover the condensate for reuse in the cycle and in general can produce the low pressures more economically. The ability to recover the condensate minimizes the make-up water needed and it's chemical treatment before being reintroduced into the cycle.

*S&V page 269*

## 25. Describe different types of Jet Condenser

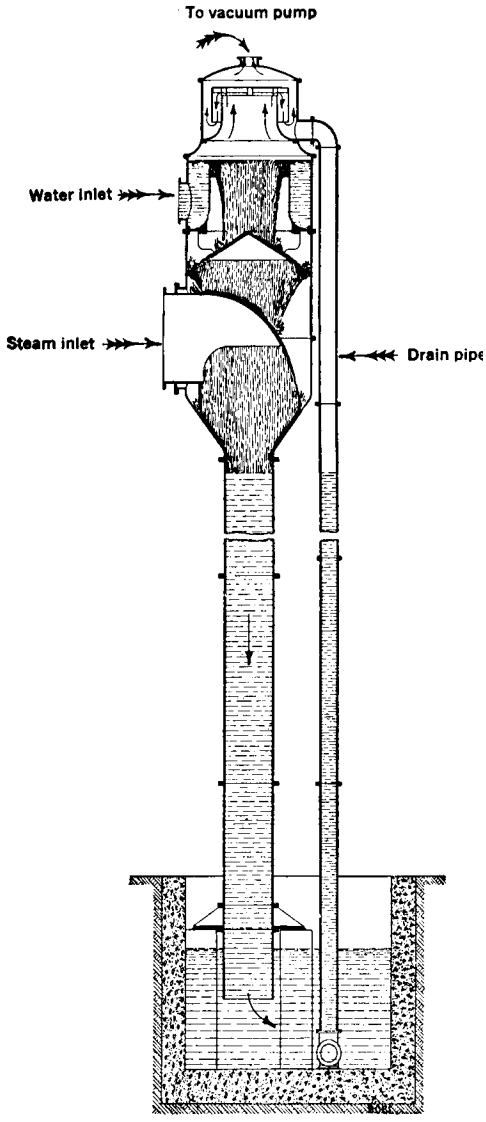
In the jet type condenser the steam and condensate

mix physically.

There are three (3) types of jet condensers.

1. Barometric

> The Barometric Condenser uses a 34 ft. to 35 ft. tail pipe. Water is discharged to the hot well according to exhaust pressure and atmospheric pressure. Air removal ejector is usually connected to head or top to maintain high vacuum. A perfect vacuum cannot raise water beyond 33 feet so there is no possibility of water being drawn into the turbine blading.




Ingersoll-Rand barometric condenser.

Figure 715.

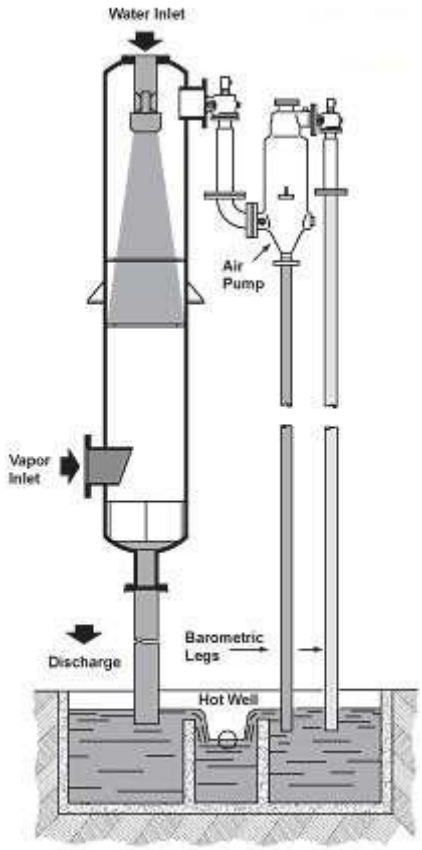



Figure 716. Barometric condenser

Figure 717. Three barometric condensers at a plant

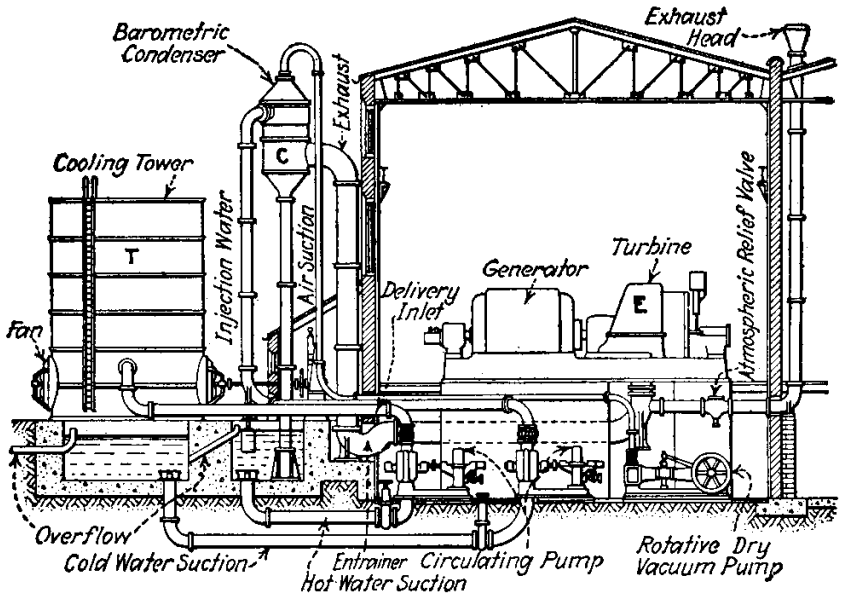



Figure 718. Steam-turbine installation with barometric-jet condenser, $C$, and cooling tower, $T$. (*Worthington Pump and Machinery Corp.*)

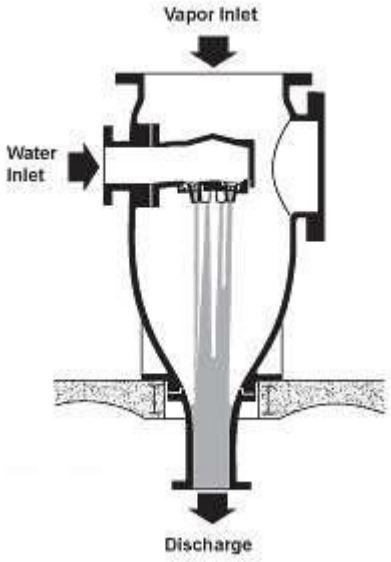



Figure 719. Top of barometric condenser with the vapor entering at the top and the water entering at the side

## 26. What is the principle of operation of a high-level-parallel-flow (barometric) jet condenser?

This condenser, also called barometric condenser, works as follows - The condenser is mounted on a long pipe (at least 34 feet) called barometric leg which acts in a way identical to a barometer. Now if water is used in a barometer then the barometric height would be 34 feet. If some vacuum exists in the condenser, the height of water column (h) will be less than 34 feet. Now it is possible, by using this condenser leg, to drain away the condensate from the condenser. If 10 feet of head difference exists between the water level in the tailpipe and the water level at the hotwell discharge, the cooling water will flow into and out of the condenser without any pumps.

## 27. What type of condenser does not need a pump once flow is started?

The barometric condenser. Steam enters the chamber at the exhaust inlet, and the injection water enters at top on the side upon entering the steam meets numerous jets of cold water. The water and the condensed steam drop to the tailpipe and then into the hot well. The condensing chamber is placed high in elevation, about 35 feet, the water is discharged from the tank without the aid of removal pump.

*Woodruff & Lammers page 506, 507*

## 28. Is a barometric condenser a type of jet condenser?

Yes.

*Woodruff & Lammers page 506*

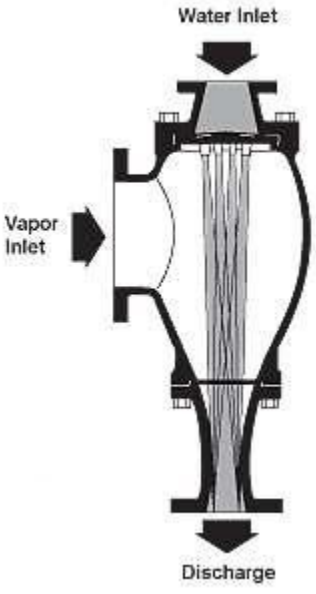



Figure 720. Top of barometric condenser with the water inlet at the top and the vapor inlet on the side.

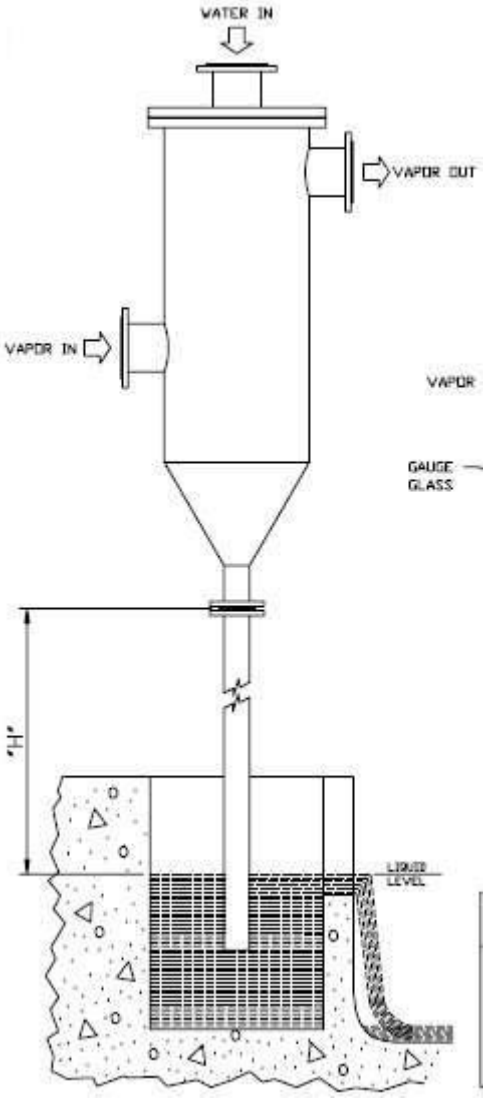



Figure 721. Barometric condenser. The broken lines signify that the pipe is much taller than the picture shows.

2. Low Level Jet

This type is in effect a barometric condenser with mixing action in the top or head of the unit. The tail pipe is not used, instead a pump removes water from the unit. Air removal equipment may also be used. A float operated vacuum breaker opens a line leading to steam space from the atmosphere if water level in the condenser rises too high. This prevents flood back to the turbine if discharge removal pump fails.

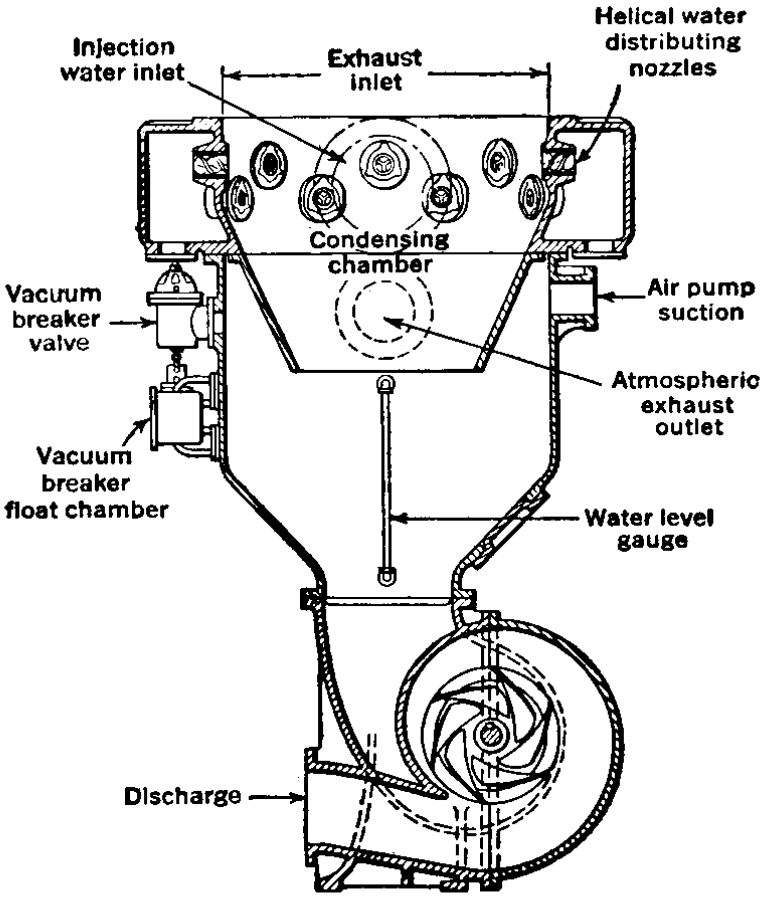



Figure 722. Foster-Wheeler low-level jet condenser.

## 29. Do low level jet condensers need a pump?

Yes

A jet condenser is a unit in which steam is condensed by direct contact with the cooling water. Jet condensers may be classified as low-level or barometric. In the low-level jet condenser both cooling water and condensate are removed from the same hot well by a pump.

*Woodruff & Lammers page 539*

3. Ejector Type

In this type high velocity jets of water condense the steam and the resulting mixture is discharged through a diffusing tube to the atmosphere. These condensers also remove air through the jet action. A vacuum breaker is used to prevent backup into the turbine for the diffuser type generally has a submerged outlet. Inlet water is supplied by a pump to supply the jet action of the water. These are used on small industrial applications.

*S&V page 269*

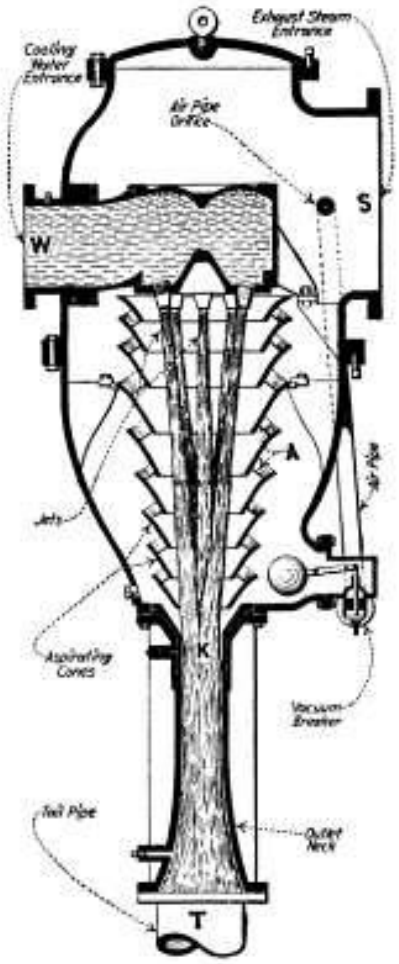
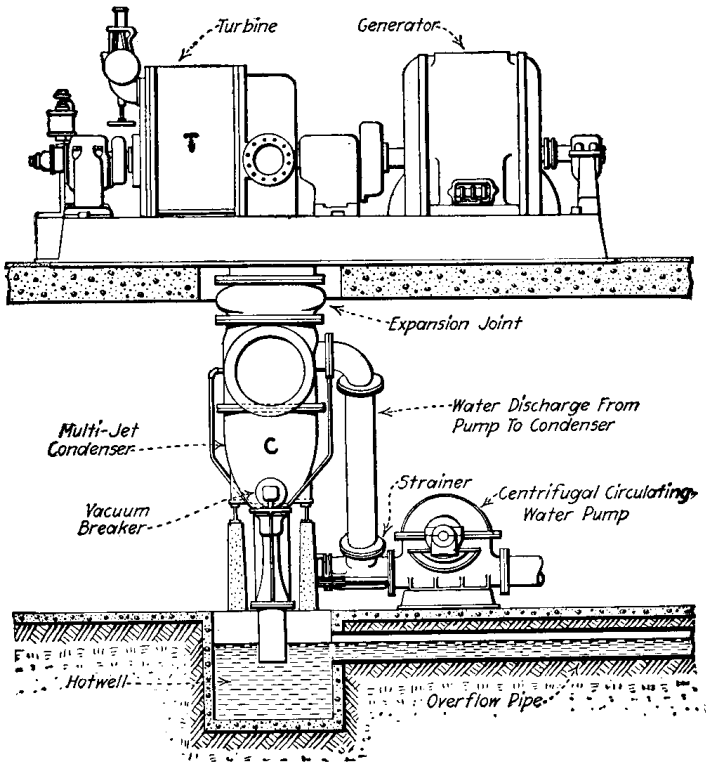



Figure 723. Ejector Jet Condenser




Arrangement of a steam turbine, *T*, with a jet condenser, *C*. (*Schutte & Koerting Co.*, "Multi-jet" condenser with which no air pump or condensate pump is required.)

Figure 724.

## 30. What are the advantages of a jet condenser over a surface condenser?

Simplicity in design.

Lower in manufacturing cost.

Lower maintenance cost.

Occupies lesser floor space.

Requires lesser amount of cooling water.

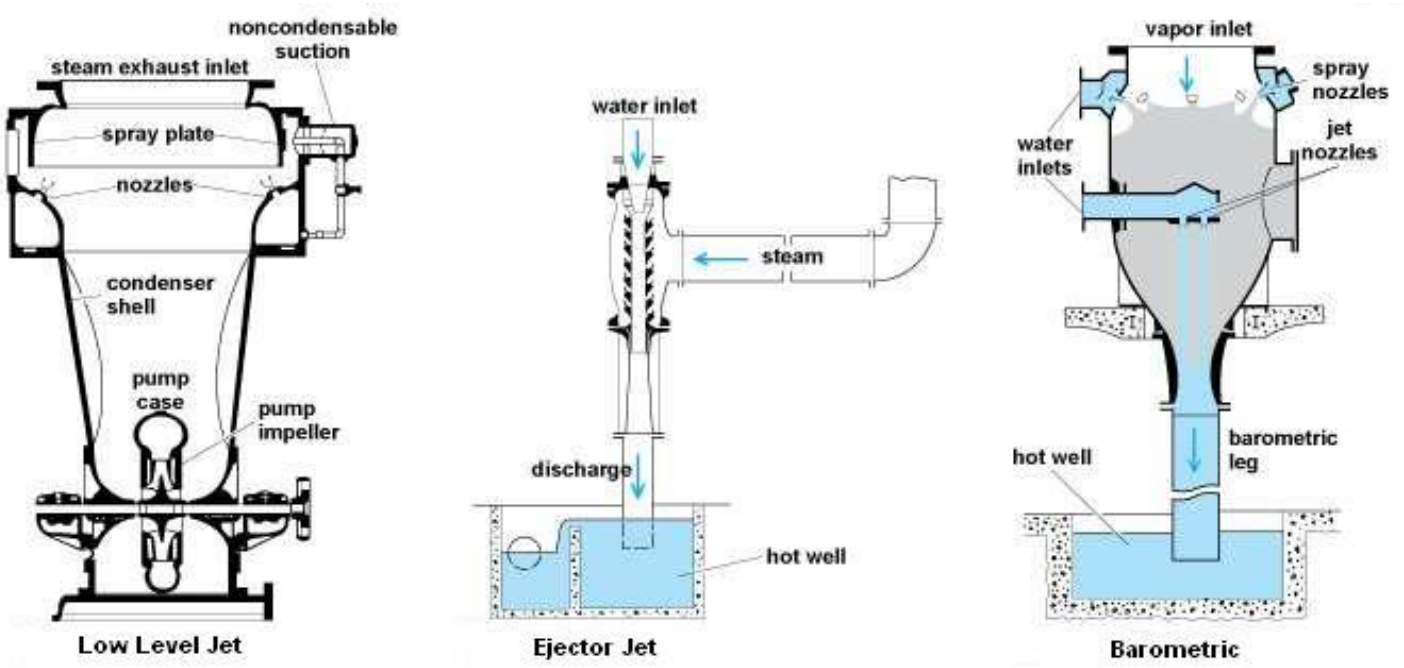



Figure 725. The three major types of direct contact condensers

# Chapter 22 Vacuum and Air Ejectors

## 1. What do you mean by vacuum?

Vacuum means any pressure below atmospheric pressure.

## 2. Why must a vacuum be maintained in the steam condenser?

By maintaining a vacuum in the steam condenser, the efficiency of the steam-power plant can be increased as greater the vacuum in the system, greater will be the enthalpy drop of steam. Therefore, more work will be available per lb. of steam condensing.

Secondly, the non-condensate (air) can be removed from the condensate-steam circuit by pulling and maintaining a vacuum in the steam side. Therefore, the condensate can be used as boiler feed.

## 3. How is vacuum in a condenser usually measured?

Vacuum can be measured by a Bourdon pressure gauge, which is calibrated to read the pressure in mm of mercury below atmospheric pressure.

The mercury vacuum gauge employed for this purpose had the general form of a barometer, and the same manner of reading was retained; that is, a perfect vacuum in the condenser, which means a perfect vacuum above the mercury column of the gauge, was said to be equal to 30 inches of mercury. There is a fundamental difference between the barometer and the vacuum gauge, however, for while the barometer indicates by the height of the mercury column the pressure of the atmosphere, the mercury vacuum gauge indicates by the height of its mercury column how much of the atmospheric pressure has been removed from the exhaust side of the piston of a condensing steam engine. Consequently, a vacuum gauge does not directly indicate the pressure existing in a condenser, but rather the amount by which the atmospheric pressure is greater than the pressure in the condenser. From this it follows as a logical consequence that the greater the indication of the vacuum gauge is, the smaller a pressure exists in the condenser. Then, if it is desired to find what absolute pressure exists in the condenser, the indication of the vacuum gauge must be subtracted from its reading when a perfect vacuum exists, and this difference must be reduced to pounds pressure per square inch. Thus, if the vacuum gauge shows that a vacuum of 26 inches exists in the condenser, the absolute pressure in the condenser is 30—26 = 4 inches of mercury, or since a column of mercury 1 inch high exerts a pressure of .491 (say .49) lb. per square inch, the pressure is 4 X -49 = 1.96 lb. per square inch, absolute.

If, instead of wishing to know the pressure in the condenser, we wish to know how much of the atmospheric pressure expressed in pounds per square inch has been removed, the indication of the vacuum gauge in inches may be multiplied by .49. Thus, if the vacuum gauge indicates 26 inches of vacuum, the pressure in pounds per square inch by which the pressure in the condenser has been reduced below the normal atmospheric pressure is 26 X .49 = 12.74 lb.

The reading of the indication of a vacuum gauge may be summed up as follows:

1. To obtain the absolute pressure in pounds per square inch in the condenser, subtract the reading of the vacuum gauge from 30, and multiply the remainder by .49.

2. To obtain the amount of pressure in pounds per square inch by which the pressure in the condenser has been reduced below the atmospheric pressure, multiply the indication of the vacuum gauge by .49.

## 4. What vacuum is carried with reciprocating engines? With turbines? Why the difference?

Vacuum for reciprocating engines is about 26.5 in. of mercury column. For turbines about 28.5 in. of mercury column. In ordinary reciprocating engine practice it is usually undesirable to carry vacuum for: (1) If the water discharged by the condenser is to be used for boiler feed, it's temperature should often, for reasons of economy, be higher than the temperature due to condensation of steam in a 26.5 in. vacuum. (2) The first of the installation would thereby be greatly increased. The greater the cost (annual charge) of obtaining each inch increase of vacuum. Prevent leakage of air through valves, stuffing boxes, and jointed connections. (3) The initial condensation in the engine cylinder resulting from the low temperature of the exhaust steam. In turbine and uniflow engine practice, however, the best results are, aside from considerations noted above regarding the feed water, obtained with the highest vacuum which it is possible to maintain. Initial condensation plays no part in this case. Also, with turbines, leakage into the condenser can be avoided with less difficulty than in reciprocating engine practice.

*Croft Steam Power Plant Auxiliaries and Accessories 2nd Ed. p. 352-354*

## 5. On what factors does the degree of vacuum in a condenser depend?

It depends on the partial pressure of steam and the partial pressure of air in the condenser.

## 6. What is the vacuum efficiency of a condenser?

It is the ratio of the actual vacuum at the steam inlet to the maximum obtainable vacuum in a perfect condensing plant, i.e., it is the ratio of actual vacuum to ideal vacuum.

## 7. Why is vacuum maintained in the steam condenser?

By maintaining a vacuum in the steam condenser, the efficiency of the steam-power plant can be increased as greater the vacuum in the system, greater will be the enthalpy drop of steam. Therefore, more work will be available per lb of steam condensing.

Secondly, the non-condensate (air) can be removed from the condensate-steam circuit by pulling and maintaining a vacuum in the steam side. Therefore, the condensate can be used as boiler feed.

## 8. If the gauge pressure of a condenser is 630 mm of Hg, what will be the absolute pressure in the condenser?

It means the pressure in the condenser is 630 mm below atmospheric pressure. The atmospheric pressure is 760 mm of Hg, the absolute pressure in the condenser.

## 9. On what factors does the degree of vacuum in a condenser depend?

It depends on the partial pressure of steam and the partial pressure of air in the condenser.

## 10. How could air enter the condenser?

With the boiler feedwater as dissolved gases.

Flange and gasket leakage.

Cooling water (for jet condenser) containing a certain amount of dissolved air in it.

## 11. What are the effects of air leakage in the condenser?

It increases the backpressure on the turbine with the effect that there is less heat drop and low thermal efficiency of the plant.

The pressure of air in the condenser lowers the partial pressure of steam, which means steam, will condense at a lower temperature and that will require greater amount of cooling water.

It reduces the rate of condensation of steam, because air having poor thermal conductivity impairs the overall heat transfer from the steam-air mixture.

## 12. How would you stop air from leaking into a condenser?

First, find the leak by passing a flame over the suspected part while the condenser is under vacuum. Leaks in the flange joints or porous castings can be stopped with asphalt paint or shellac. Tallow or heavy grease will stop leaks around the valve stems. Small leaks around the porous castings, flange nuts, or valve stems can always be found by the flame test. So, you might have to put the condenser under a few pounds of air pressure and apply soapsuds to the suspected trouble parts.

## 13. What should you do if you lost vacuum while operating a condensing turbine plant?

If vacuum is lost **shut down** immediately. The condenser cannot withstand steam pressure; the condenser tubes may leak from excessive temperature. Excessive pressure will also damage the shell, the exhaust, and the low-pressure parts of the turbine.

## 14. How do you test for vacuum leaks in condenser tubes?

Helium detection is widely recognized as the superior alternative to the ultrasonic, smoke, and the shaving cream method of vacuum leak detection on steam turbine condensers.

**HELIUM LEAK TESTING - WHY USE HELIUM FOR LEAK DETECTION?**

There are many benefits to using helium as a *leak test* method:

Helium is the smallest atom (after hydrogen) so easily reaches the parts other atoms can't reach

Helium is present in the atmosphere in sufficiently low quantities so as not to affect testing

Helium is inert, so safe to use for testing. Unlike other tracer gases, residual helium left in the component will not react with any gas/liquid which the component is charged with in its normal operation

Helium has a unique mass number (4) enabling mass spectrometers to be 'tuned' to only see helium

Helium costs are relatively low - in high consumption processes. Helium recovery units can be used to obtain high recovery rates

Helium is naturally occurring in the atmosphere and can be safely discharged without any adverse environmental effects

# Air Ejectors

## 15. What auxiliary equipment is required for operating a steam condenser?

Cooling water (which may be cold condensate) circulation pump. Generally, it is a centrifugal one.

Arrangement for cooling the condensate (i.e., a heat exchanger) in case the condensate is recycled to extract heat from the exhaust steam.

An air pump or steam ejector to remove air and other non-condensing gases from the condenser.

An extraction pump (usually centrifugal) to remove the condensate from the condenser.

## 16. Explain the condenser air-removal equipment.

In the steam space of a condenser, either of the jet or surface type, there is always a certain amount of air and other non-condensables which unavoidably gets in. This air may come from turbine gland leakage, porous exhaust hoods, drains, flexible condenser joints, air in the circulating water of jet condensers, or any air originally in the steam. Air leakage may run from about 1.5 to 6 cfm for surface condensers in good condition. This air is in general not removed with the condensate and circulating water, and tends to concentrate in the condenser and so increases the turbine exhaust pressure. The air is usually diffused throughout the steam in the steam space. It is, therefore, removed by some form of pumping equipment which has its suction in the steam space and draws out a mixture of air and steam. A number of different types of pumps have been used, but the most common and most widely used equipment today is the steam jet air ejector which has been standard equipment for condensers since it supplanted the reciprocating and hydraulic types of vacuum pump. In these units high-velocity steam jets entrain the air and vapor mixture led from a condenser by an air offtake pipe. The steam jets picking up this mixture at condenser pressure have enough power to discharge it to the atmospheric pressure through diffuser tubes. Steam at about 100 to 300 psig is commonly used for its operation. A two-stage ejector is generally required for vacuum greater than 26 inches Hg. One stage suffices for lesser vacuum. Circulating make-up or condensate from the hot well through intermediate and aftercondensers recovers the heat in the steam from the jets. Parallel jets are used for added capacity. The multijet unit lends itself to more efficient part-load operation by stopping some of the jets and allowing the remainder to work at best efficiency.

*S&V pages 277-278*

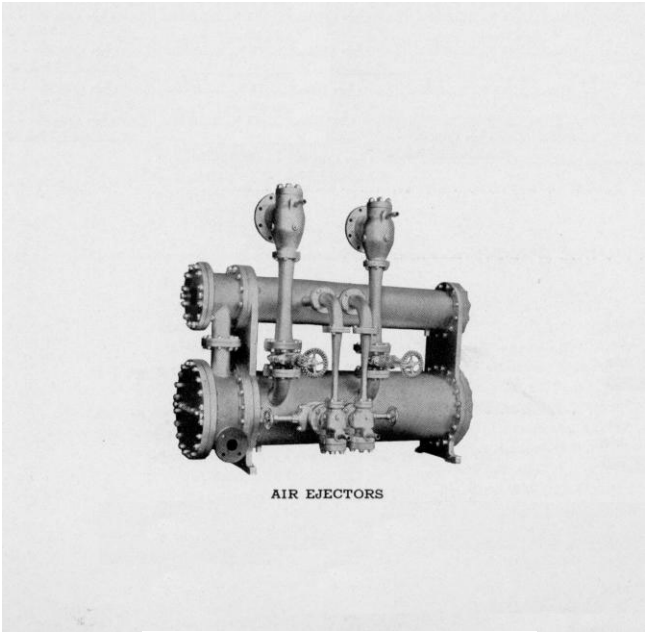



Figure 726. Two stage air ejector

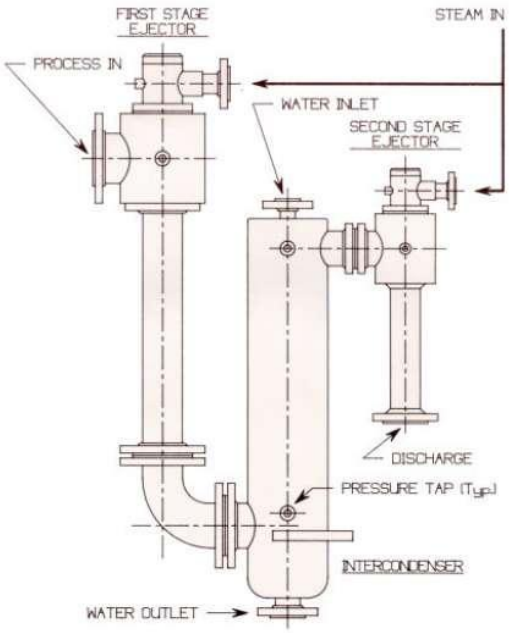


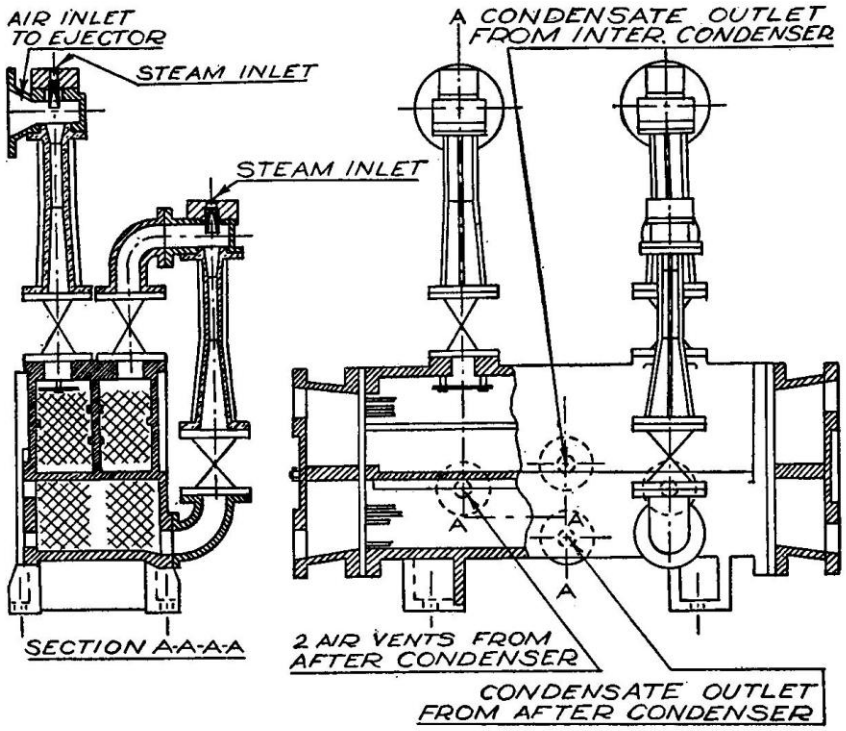

Figure 727. Two stage air ejector

## 17. What is an air ejector and how does it work?

An air ejector is a steam siphon that removes air and other non-condensable gases from the condenser. If left in the condenser air would drive up turbine exhaust pressure lowering turbine efficiency.

*S& V page 277*

In the ejector a mixture of steam and non-condensables is drawn off the condenser through the air offtake connection. High velocity steam jets entrain the air and vapor mixture and discharge it to the condenser or the atmosphere. 100 to 300 PSI steam is commonly used. Two stage ejectors are required for vacuums over 26 in. hg. The first stage ejector discharges to the inter-condenser while the second stage discharges to the aftercondenser. A vent line on the aftercondenser has a meter to record the amount of air discharged to the atmosphere.




AIR EJECTORS WITH INTERCOOLER

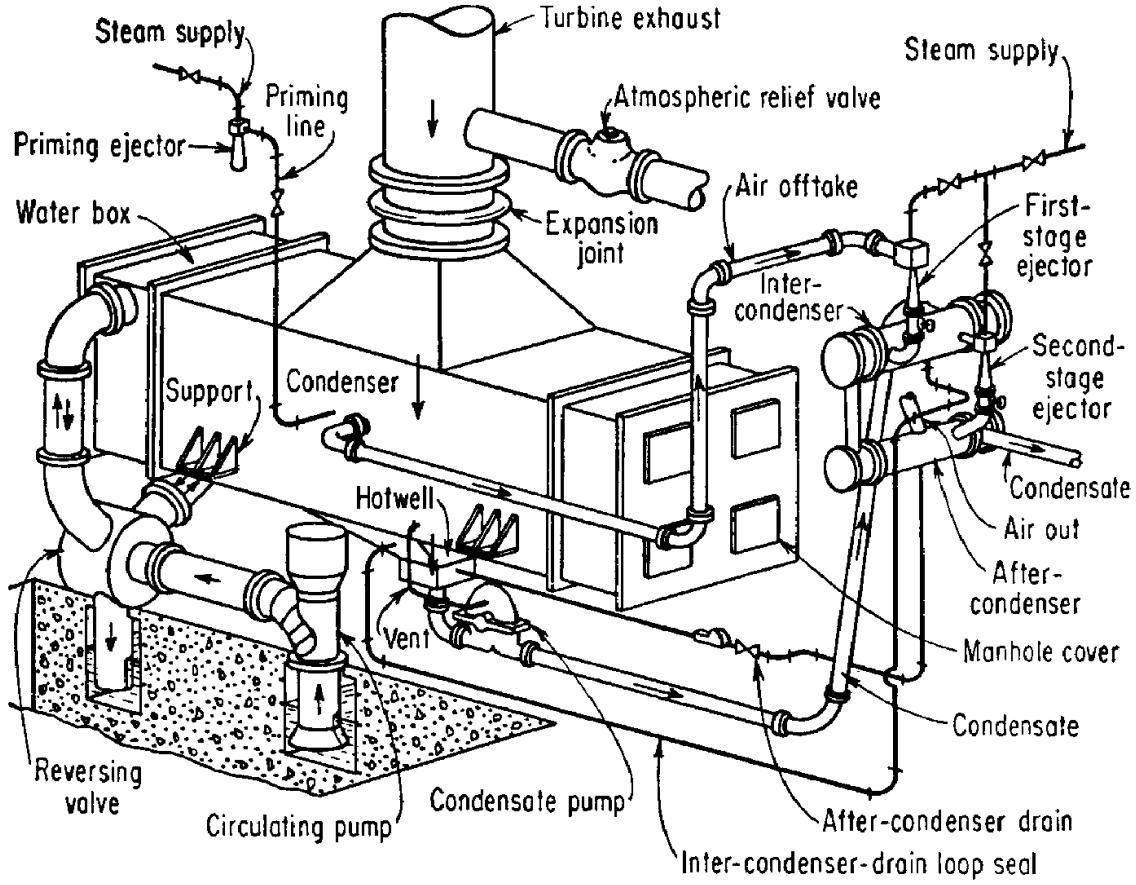
Figure 728.

## 18. What medium is responsible for operating an air ejector?

Steam

The most common and most widely used equipment today is the steam-jet air ejector which has been standard equipment for condensers since it supplanted the reciprocating and hydraulic types of vacuum pump.

*S&V page 278*




**Auxiliaries shown are needed to keep a modern surface condenser working at an efficient capacity.**

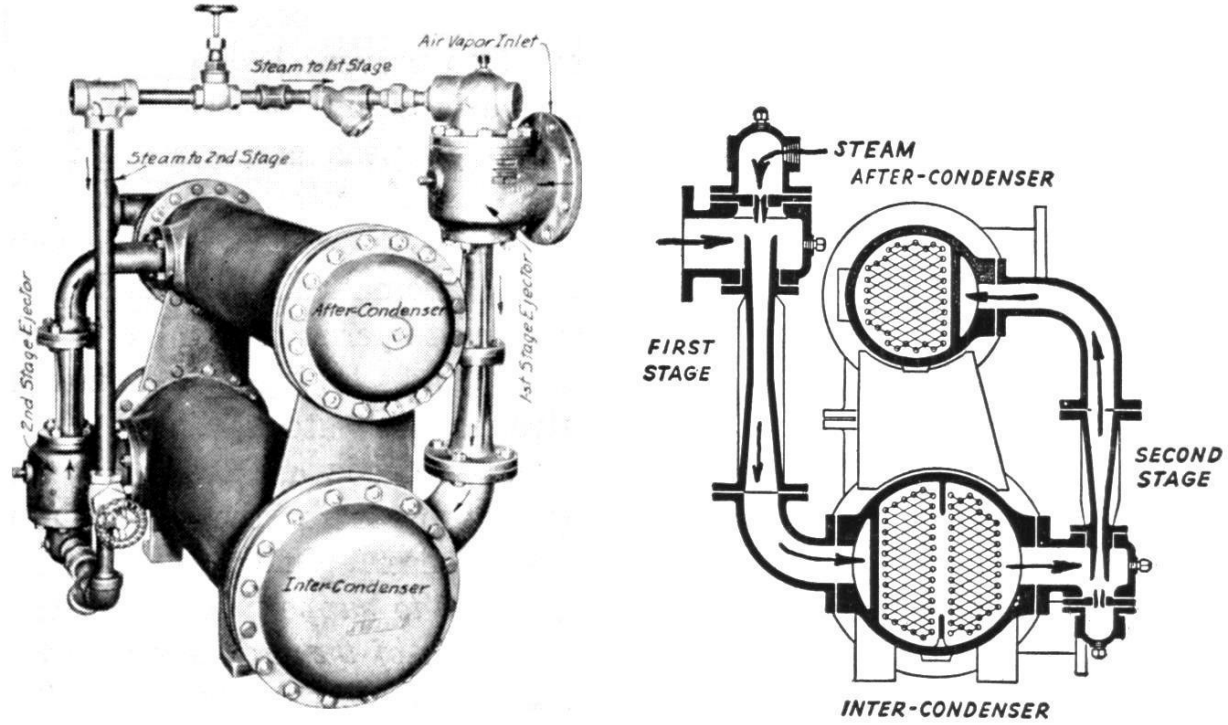
Figure 729. A condenser with all the auxiliaries attached. Note the inter-condenser loop seal and the after-condenser drain trap.

## 19. Why are two stage air ejectors found on condensers?

To make air and noncondensable gases pass up through the water curtain to the air-vapor outlet and from there to a two-stage ejector system. The noncondensable gases are aspirated from the intercondenser and are discharged to the atmosphere.

Cooling steam into water collapses it 1600 times smaller than it was. This is the main source of vacuum in the condenser. The air ejector initiates the vacuum at startup and helps maintain the vacuum in the condenser during operation, but the water travelling through the condenser sustains the vacuum. If the cooling water flow is lost, the air ejector cannot maintain the vacuum and the turbine must immediately be shut down.

*Woodruff & Lammers page 507*




Elliott Type C Air Ejector — Outside and Section.

Figure 730.

## 20. Where would you look for a fault if the air ejector did not raise enough vacuum?

In this case, the trouble is usually in the nozzle. You will probably find that:

1.) the nozzle is eroded

2.) the strainer protecting the nozzle is clogged

3.) the steam pressure to the nozzle is too low

## 21. What is used to condense the steam in the intercondenser and aftercondenser of a two stage air ejector?

Condensate from the hotwell is pumped through the intercondenser and aftercondenser to remove heat from the steam. In this way the heat is recovered in the condensate and reused in the feedwater system without being wasted.

*S&V page 282*

Main condenser condensate is used for circulating water in the intercondenser and aftercondensers

*Croft Auxiliaries and Accessories page. 281*

## 22. What type of trap is used on the intercondenser of an air ejector?

A loop seal or drain trap handles condensate from the intercondenser.

*Croft Auxiliaries and Accessories page 280*

## 23. How do you remove condensate from the aftercondenser of an air ejectors?

A drain trap is used for the aftercondenser.

*S&V page 279*

The steam jet air ejector is the most efficient type of high vacuum pump and is widely used in modern power plants. Its purpose is the removal of air from the main steam condenser. Ejectors are classified as single stage, two stage, or three stage. The single stage unit will develop a vacuum of 26.5" Hg. and the two stage unit will develop a vacuum of 29.5 Hg. Three stage units are rarely used. Condensate from the hot well is used as the condensing medium in the intercondenser and aftercondenser. The drains from the inter condenser are returned through a loop seal to the condenser steam space. The drains from the after condenser are returned to the hot well through a trap due to the greater pressure differential.

The type of trap used is ball float.

*D.E.S.C. Condensers page 12*

*S&V page 282*

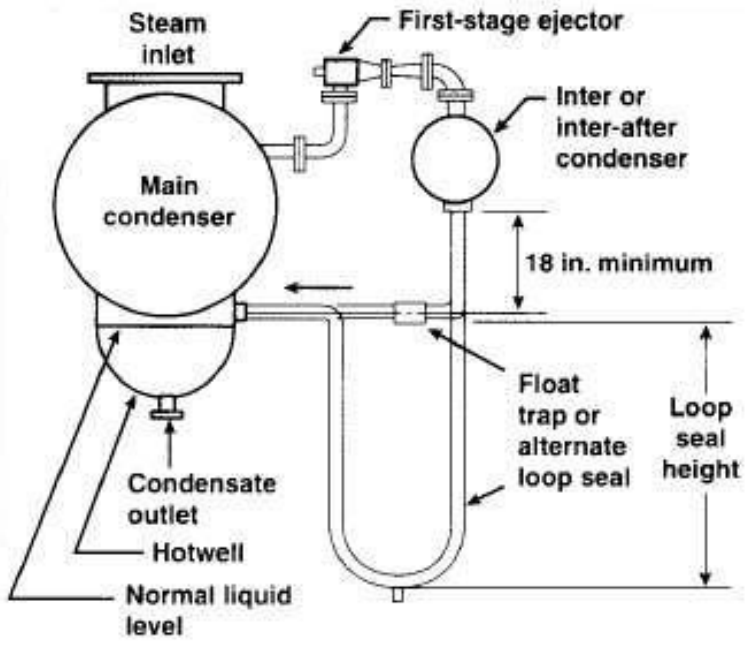
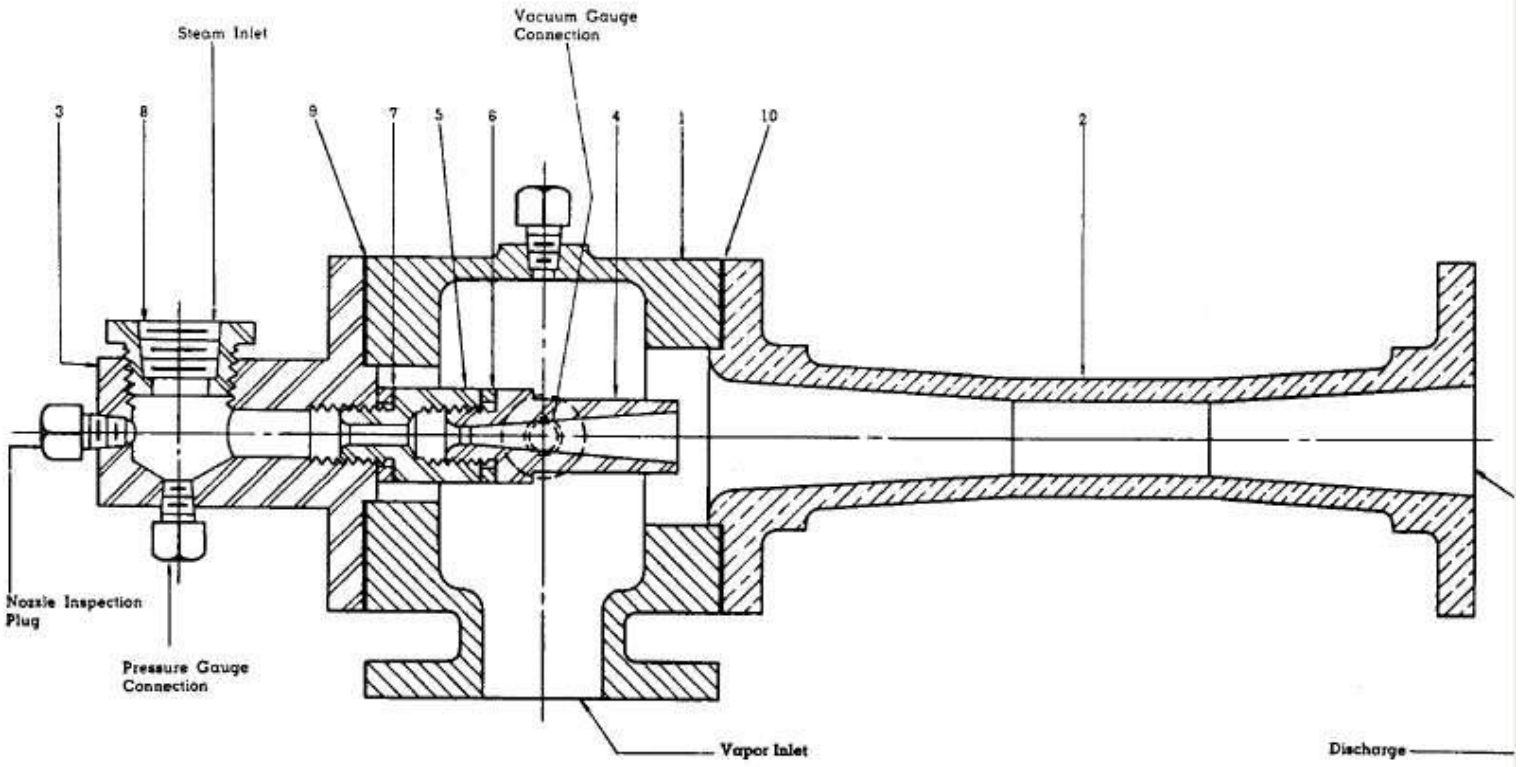



Figure 731. Loop seal

## 24. What is a hogger used for?

A hogger jet or auxiliary single stage non-condensing ejector may be used to remove large quantities of air from the system during start-up. This evacuator is cut out at around 20 in. hg. The main ejector is then used.




NAME OF PARTS

| | |
|---|---|
| 1. Suction Chamber | 6. Nozzle Spacer |
| 2. Diffuser | 7. Extension Spacer |
| 3. Steam Chest | 8. Reducing Bushing |
| 4. Nozzle | 9. Gasket |
| 5. Extension | 10. Gasket |

Figure 732.

**Spare and Replacement Parts for Type "E" Ejectors**

When ordering spare or replacement parts, please give part name and number as well as the ejector serial number and Elliott order number given on sheet PIB-1.

## 25. Starting a single-stage (hogging jet) air ejector:

1. Open discharge valve to outside air.

2. If a small condenser is provided with the hogging jet, turn on water supply valve.

3. Open the steam valves, admitting steam from a supply line at the proper pressure.

4. Open the air inlet valves.

As soon as the full steam pressure is supplied in the steam chamber, the ejector will start operating. The vacuum will be gradually increased as the air is removed from the system and after a short interval of time the normal operating vacuum will be obtained.

## 26. Shutting down a single stage (hogging jet air ejector:

1. Close the air inlet valves.

2. Close the steam supply valves to the hogger.

3. Close the water supply valve.

4. Close the discharge valve to the outside air.

## 27. Why is the second stage of a two stage air ejector started before the first stage?

The entrained air in the condenser has to be relieved to the outside air otherwise a vacuum cannot be obtained. The air outlet is on the second stage of the air ejector. If the first stage was started first, a pressure would be developed in the intercondenser.. Starting the second stage first allows the intercondenser to be evacuated preventing the first stage from having to operate against a back pressure.

## 28. When should vacuum be increased when starting a turbine?

The vacuum should be increased as the turbine comes up to its operating speed you increase the vacuum by operating the steam valves to the air ejector

*Woodruff and Lammers 6th ed. pgs 542*

## 29. Start a two stage ejector:

1. See that both steam valves are closed

2. Open the air exhaust valve at the discharge of the second stage element or aftercondenser.

3. Open the air inlet valve at the inlet of the first stage air ejector.

4. Open the valve in the inter-condenser drain loop.

5. Open the drain valve in the after-condenser drain line (if the intercondenser and aftercondenser are of the surface type).

6. Start water circulating through the intercondenser and aftercondenser.

7. Open the main steam supply valve, admitting steam at the proper pressure from the steam lines.

8. Open the steam valve to second stage air ejector. As soon as the full steam pressure is supplied to the steam nozzle, the ejector will start to operate. An interval of time should be allowed to build up the vacuum to approximately 16-20 inches.

9. Then open the steam valve to the first stage air ejector. After another short interval of time, the normal operating vacuum will be obtained.

## 30. Shutting down two stage air ejectors:

1. Close the first stage air ejectors air inlet valve.

2. Close the steam valve to the first stage air ejector.

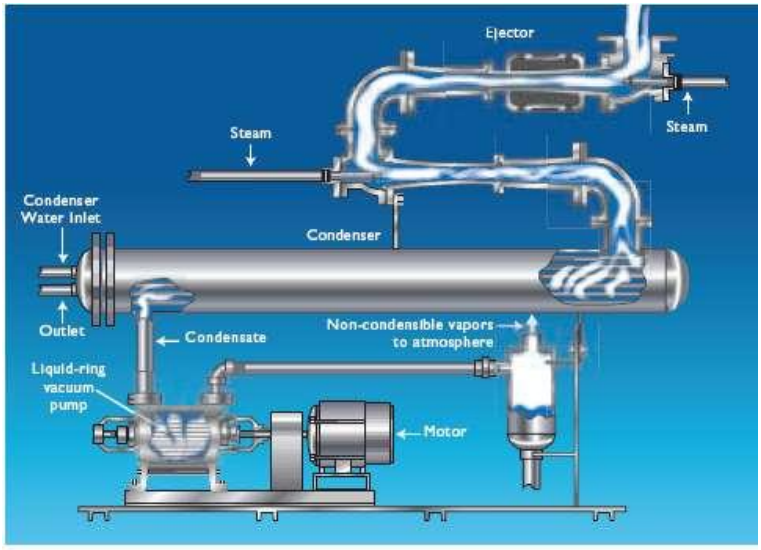
3. Close the steam valve to the second stage air ejector.

4. Close the main steam supply valve.

5. Close the condensing water supply valve to the inter-condenser and the after-condenser.

## 31. Are there other ways of obtaining a vacuum other than air ejectors?

Sometimes a liquid vacuum pump is used in conjunction with air ejectors.




*In this low-maintenance system, the only moving part is the impeller of the liquid-ring vacuum pump. And, no special vacuum oils, lubricants or special cooling systems are needed.*

Figure 733.

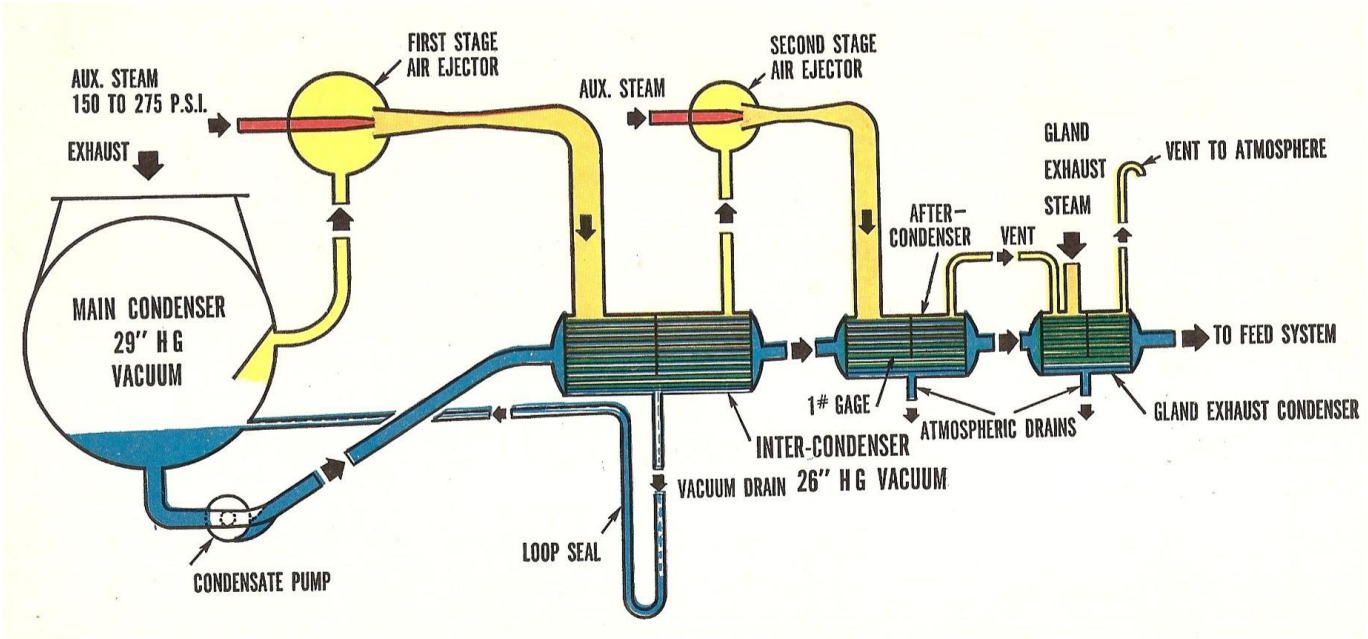



Figure 734. Two stage air ejector diagram

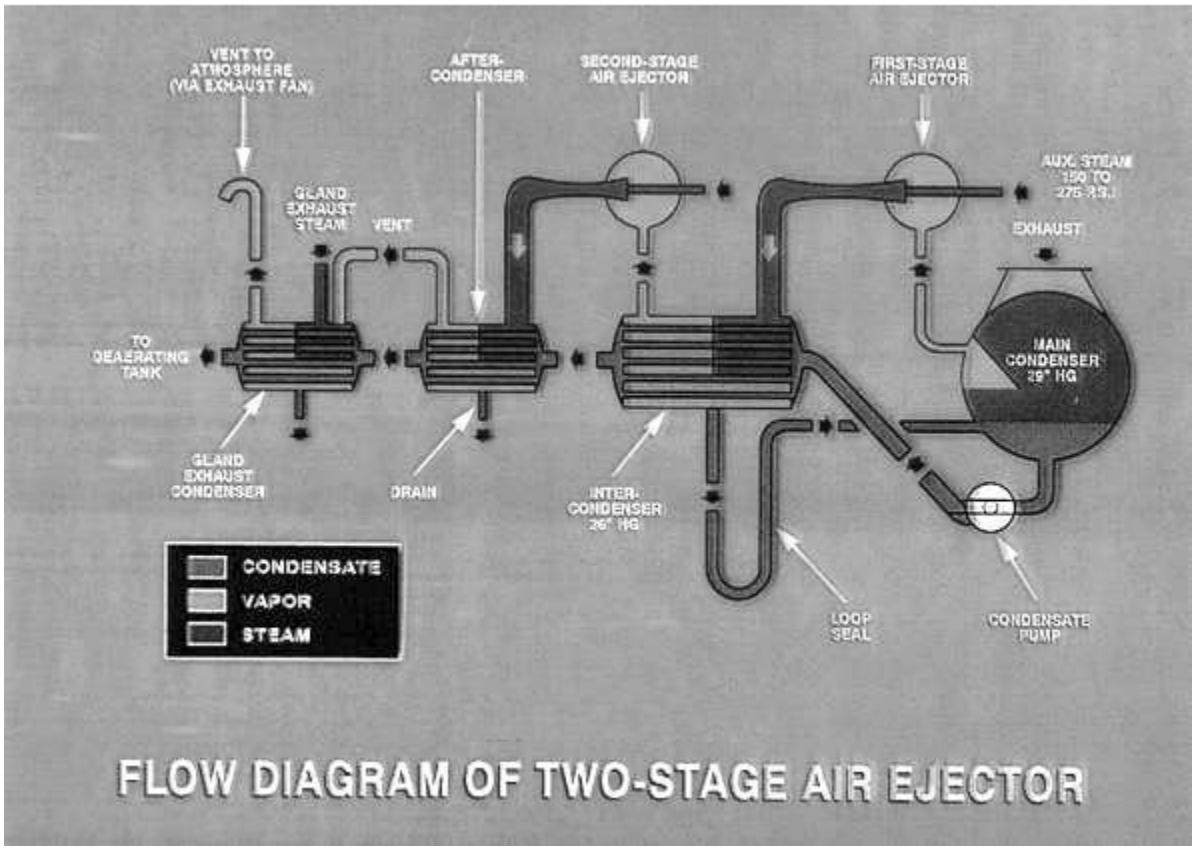



Figure 735. Two stage air ejector diagram

(Two-Stage System with Inter- and Aftercondenser)

Figure 736.

# Chapter 23 Reheat Turbines and Reheat Control

## 1. What is the reheat cycle?

In the reheat cycle, superheated steam is expanded in a high-pressure turbine and then returned to the boiler's re-heater to raise the temperature of the steam to the inlet temperature, usually to around 1000° F. It is then returned to the turbine to be expanded through intermediate-pressure turbines. In some cases, the steam is again returned for re-heating in the boiler and then expanded in the lower-pressure sections of the turbine. The main purpose of re-heating the steam on large turbo-generators is to avoid condensation in the lower-pressure sections of the turbine, which can rapidly cause blade erosion problems from wet steam.

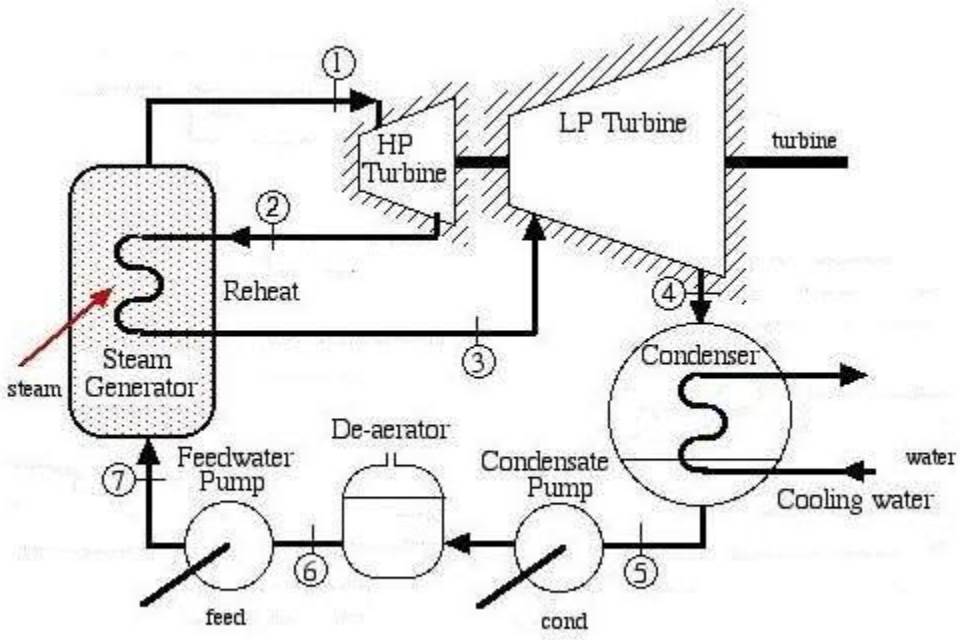



Figure 737. Steam at 1000 degrees goes into the High Pressure turbine at (1). It leaves the High Pressure at 400 degrees at (2) and then goes through the reheater. The reheated steam at 1000 degrees but at a lower pressure at (3) goes into the Low Pressure turbine. The exhaust steam leave the turbine at (4) and is turned back into water in the condenser. The condensate at (5) goes through the de-aerator at (6) and into the feedwater pump and back into the boiler at (7).

## 2. Describe a reheat turbine cycle.

Expansion at high efficiency from high pressures, with moderate steam temperature, to a high vacuum results in excessive moisture in the low-pressure stages. To avoid this, and to improve station economy, steam can be withdrawn from the turbine at an intermediate stage, reheated by flue gases, live steam, or other hot fluid, and then returned to the turbine. This results in a reheating turbine. Some of the main reasons to use a reheat cycle are:

1. Thermal efficiency increased.

2. Boiler feed pump power reduced by 15 to 18 per cent.

3. Condenser size reduced by 7 to 8 per cent.

4. Main steam generator reduced in size as a result of 15 to 18 per cent less steam flow.

5. Turbine exhaust moisture reduced by about 50 per cent.

6. Feedwater heating equipment reduced in size.

*Kents 11th Edition. page 8-09.*

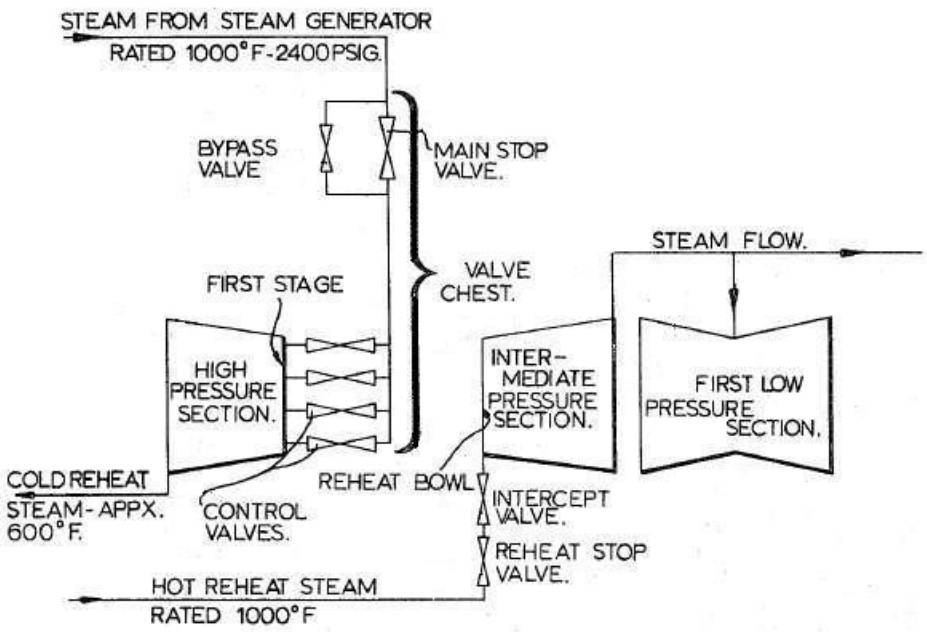



Figure 738. Exhaust steam from the cold reheat goes back into the boiler for reheating to 1000 degrees Fahrenheit. It must pass through the reheat stop valve and the intercept valve before it can enter the intermediate section of the turbine.

## 3. Explain pre-emergency governor operation and what it controls.

The pre-emergency governor controls the intercept valve and begin closing it at 1% overspeed. It is fully closed at 5% overspeed. The pre-emergency governor is built into the speed controller. Through mechanical or hydraulic lines and linkages the movement of the governor is transmitted to the valve. The pre-emergency governor also controls the dump valve.

*Grubbs Notes Turbine Section page 16, D.E.S.C. Modern Turbines page 5*

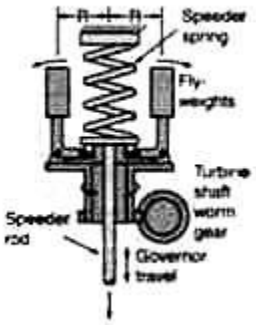



Figure 739. Pre-emergency governor

Figure 740. Another style of pre-emergency governor

The pre-emergency control devices take control away from the normal governing devices as soon as certain abnormal conditions exist which, however, are within a safe operating range. After such a disturbance, and as conditions come back to normal, control is transferred back to the normal governing devices and the pre -emergency control system again stands ready to take care of new disturbances without direct action of the operator.

**The Pre-Emergency Speed-Governing System**

On reheat units there is an appreciable volume of steam entrained in the reheater between the high pressure section and the intermediate-pressure section of the turbine. The energy stored in this steam volume would be able to accelerate the turbine rotor to a peak speed of from 125 to 155 percent of rated speed, depending on the turbine -boiler combination, if full load were lost instantly and there were no valves to stop the steam flow from the reheater to the intermediate-pressure section of the turbine. In order to keep the unit under control of the speed governor following a full-load dump, the pre-emergency speed control starts closing the intercept valves located just upstream from the intermediate-pressure section of the turbine at 101 percent of rated speed, and closes them fully at 105 percent of rated speed. The pre-emergency control will then allow the trapped steam to bleed down, keeping the turbine at about 104 percent speed until the energy in the reheater is used up and the speed drops to below 101 percent of rated. Control is then automatically transferred back to the main speed governor.

*Turbine -Generator Controls, Protections, and Accessories by G. W. Cunningham*

## 4. With a turbine using a reheat cycle what happens to the steam if the turbine lost its load too quickly?

Intercept valves are provided on reheat turbines. Their purpose is to prevent overspeeding of the turbine upon sudden loss of load. The intercept valve is located in the reheat line to the turbine and are usually mounted on the casing. They are controlled by the pre-emergency governor which starts closing at 1% overspeed and the valves are fully closed at 5% overspeed.

*D.E.S.C. Modern Turbines page 8*

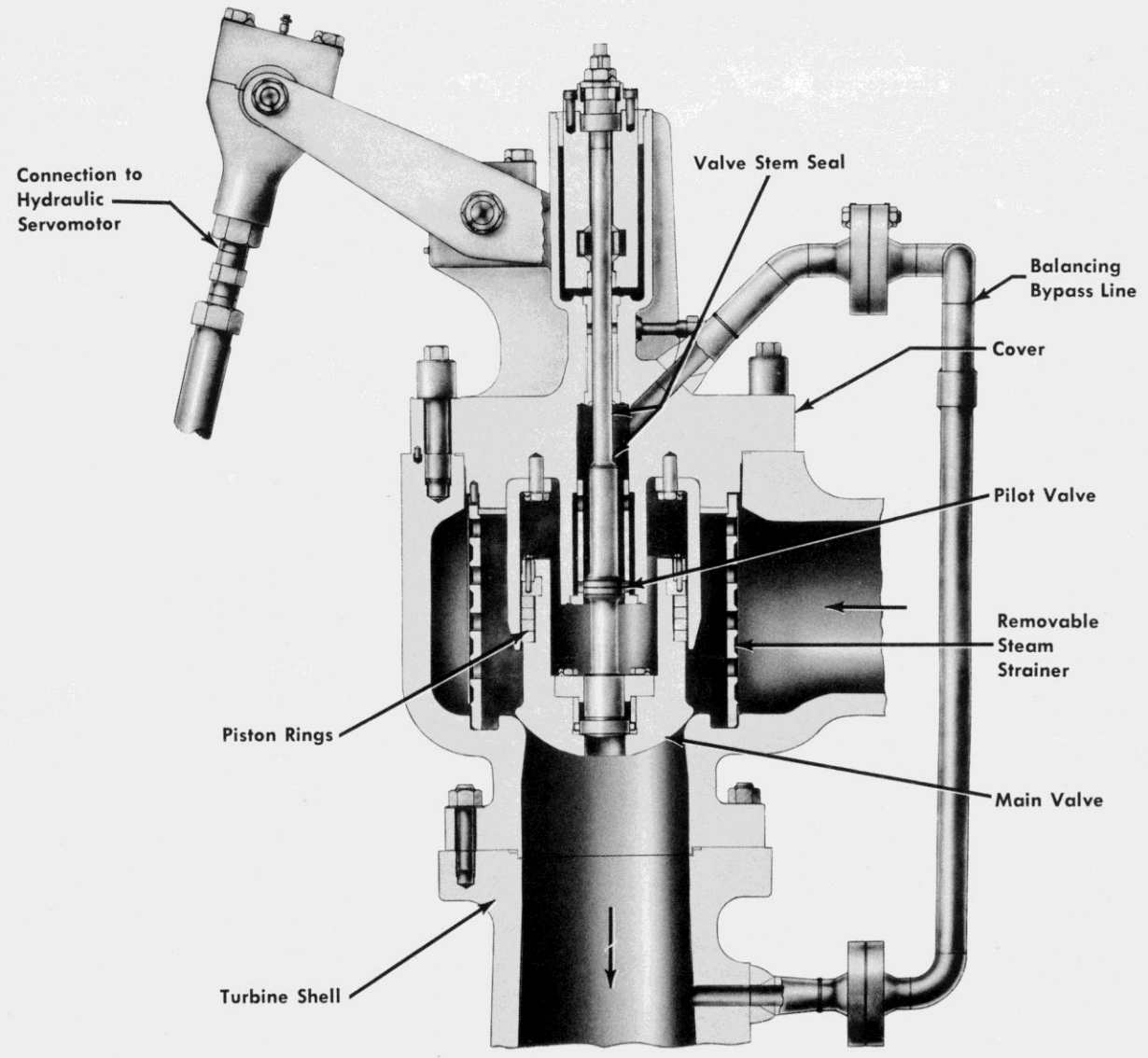



Figure 741. Intercept Valve

## 5. Where is the reheater inlet on a triple tandem turbine?

The reheater is located between the high pressure or first stage turbine and the intermediate pressure or second stage turbine on a triple tandem turbine.

On a double tandem turbine it is located between the low and high pressure stages.

*D.E.S.C. Modern Turbines page 3*

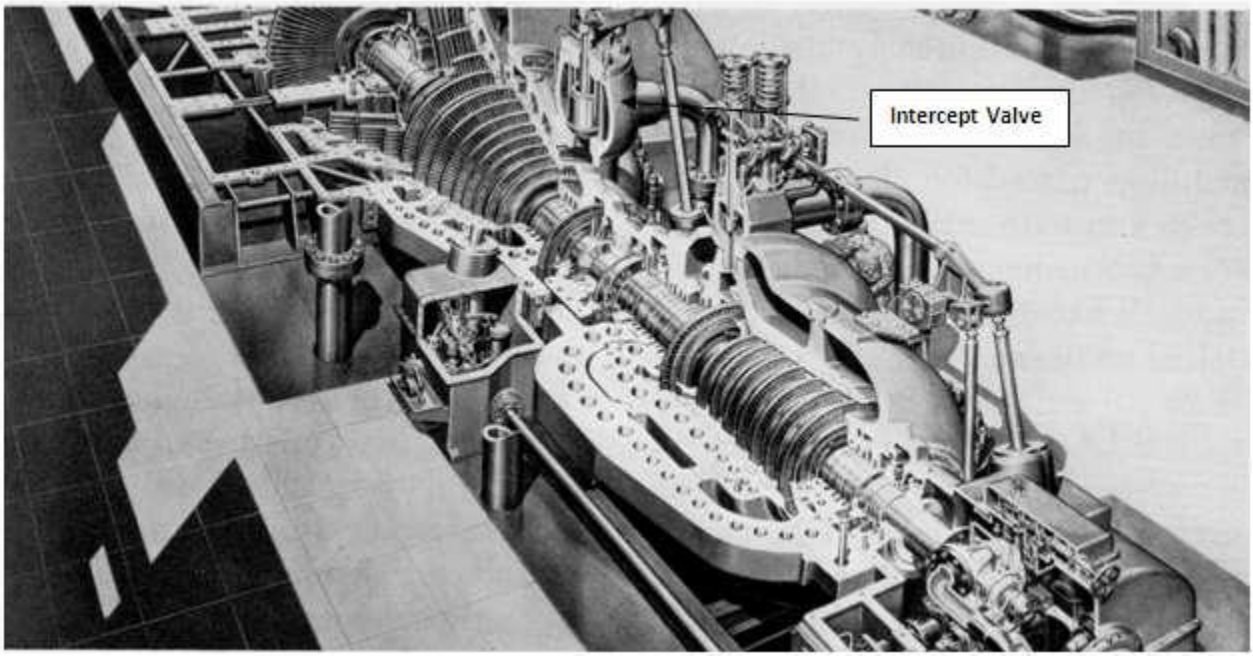



Figure 742. Location of intercept valve on the casing of the reheat turbine

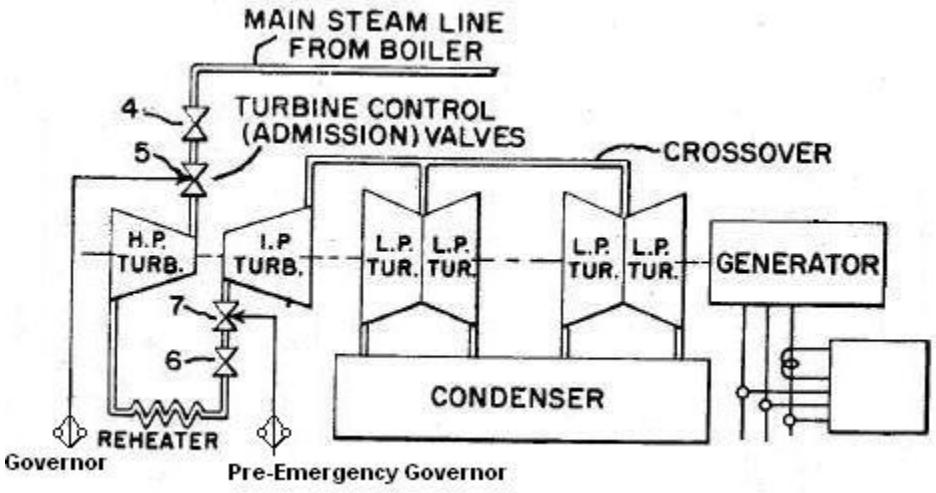



Figure 743. #4 is the main steam stop valve, #5 represents the bar lift or cam lift admission valves, #6 is the reheat stop valve and #7 is the intercept valve. Notice that the reheat stop valve and the intercept valve are on the inlet to the Intermediate Pressure Turbine. The Intercept valve is a modulating valve closest to the turbine casing controlled by the pre-emergency governor. The reheat stop valve #6 is either fully open or fully closed.

## 6. What is an intercept valve on a turbine and where does it dump its steam to?

The intercept valve is a automatic shut off valve located on the reheat steam line and usually mounted on the turbine casing. Its purpose is to prevent turbine overspeeding in the event that the turbine loses its load. It is operated by the pre-emergency governor. It usually dumps its steam to the condenser through a dump valve.

*D.E.S.C. Modern Turbines pages 4 & 5*

Figure 744. Intercept valve

Steam Dump Valve
• Noise Reduction Trim that Varies from Single Stage to Lo-dB to V-Log Depending on Actual P1/P2 Ratio
• Pilot Plug is Used to Provide Class V Seat Leakage
• Custom Sparger Designed Available for Turbine Bypass Control Valves

Figure 745. Steam Dump Valve

## 7. Explain a dump valve.

Dump valves are usually provided where intercept valves are used. Their purpose is to relieve the steam trapped in the reheat section when the intercept valve closes. The dump valve relieves to the atmosphere or to the condenser where the steam can be reclaimed.

The dump valve is operated through linkages by the pre-emergency governor.

Overspeed trip takes about 1 second.

*D.E.S.C. Modern Turbines pages 4 & 5*

### TURBINE BYPASS AND CONTROL

Another major function of the turbine bypass system is to avoid a steam system overpressure event, resulting in the lifting of safety valves, and subsequently creating a maintenance/outage problem associated with repairing the valves. To accomplish this, the bypass valves operating in "fast-acting" (vs. modulating) mode actuates upon sensing an overpressure event in the main steam and/or hot reheat lines, or upon receipt of a steam turbine generator trip signal. The turbine bypass system diverts the system flow around the steam turbine generator to the condenser, which provides the ultimate heat sink. This serves to drop the system pressure, while still passing sufficient flow to maintain HRSG superheater and reheater section cooling. The valves on this part of the system act as "steam dump valves". The turbine bypass system incorporates Valvtechnologies, Inc. Xactrol Mark III control technology with the patented ringed, conical disc stacks.

Figure 746.

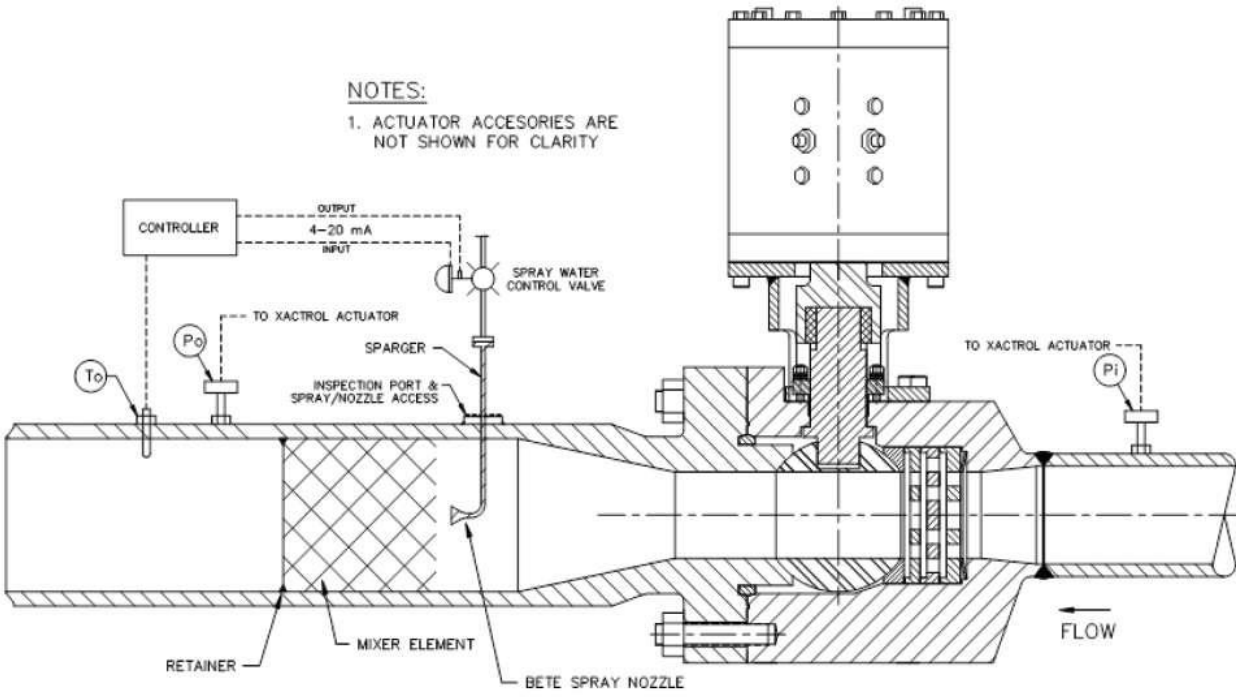



Figure 747. Steam Dump Valve with water sprays for cooling

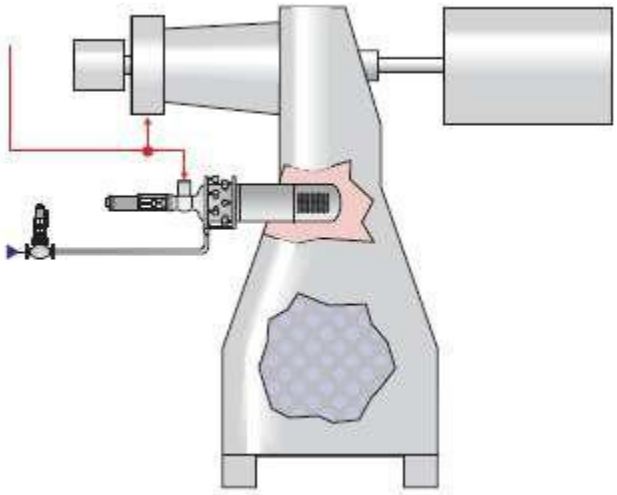


Figure 748. Steam dump valve placement inside condenser

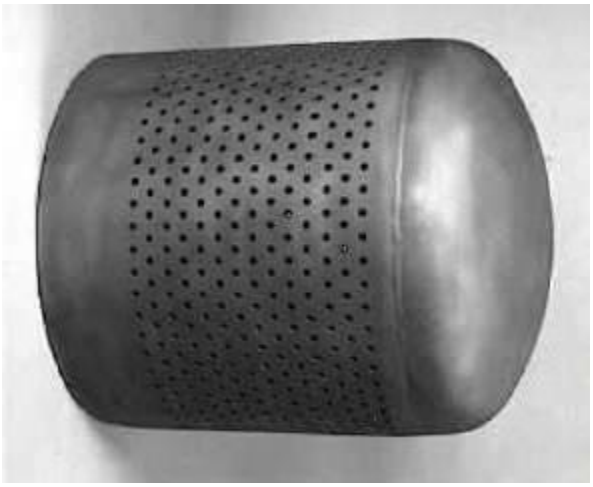


Figure 749. Steam Dump Valve nozzle

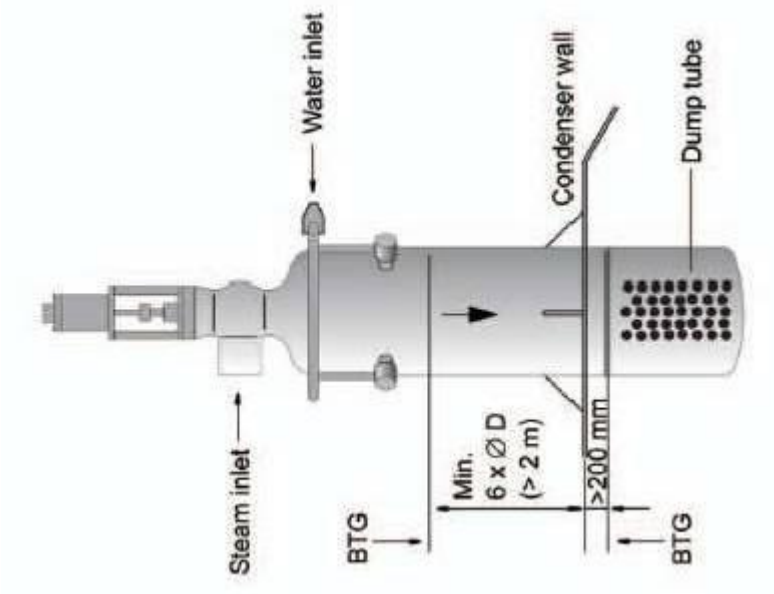



Figure 750. Steam Dump Valve

## 8. What is the purpose of the reheat stop valve?

The reheat stop valve is controlled by the overspeed trip. The overspeed trip will close the main steam stop to high pressure turbine and close the reheat stop valve.

The Reheat stop valve is an emergency stop valve in the reheat line used to prevent overspeed.

These valves are provided as a means of exercising the intercept valves.

*D.E.S.C. Modern Turbines page 5, Notes from Grubb's Class, Grubb Notebook page . 16*

Figure 751. Reheat Stop Valve under insulation

## 9. Describe a reheat stop valve operation.

A reheat stop valve is installed in the reheat line between the reheater and the intercept valve. Its purpose is to furnish an additional safety device to prevent overspeeding of the turbine, should the intercept valve fail to close when the overspeed trip mechanism operates.

When the overspeed trip mechanism operates, oil is released from beneath the poppet valve to drain through the overspeed trip valve. The poppet valve moves downward, connecting to the chamber beneath the operating piston to drain. The compression spring moves the piston downward closing the disc against its seat, thus preventing flow of steam from the reheater to the turbine.

A hole drilled through the disk permits sufficient steam to pass through, to balance the valve in its closed position, with the intercept valve closed, but not an amount sufficient to overspeed the turbine.

*Mistersky #6 Boiler Operations Manual*

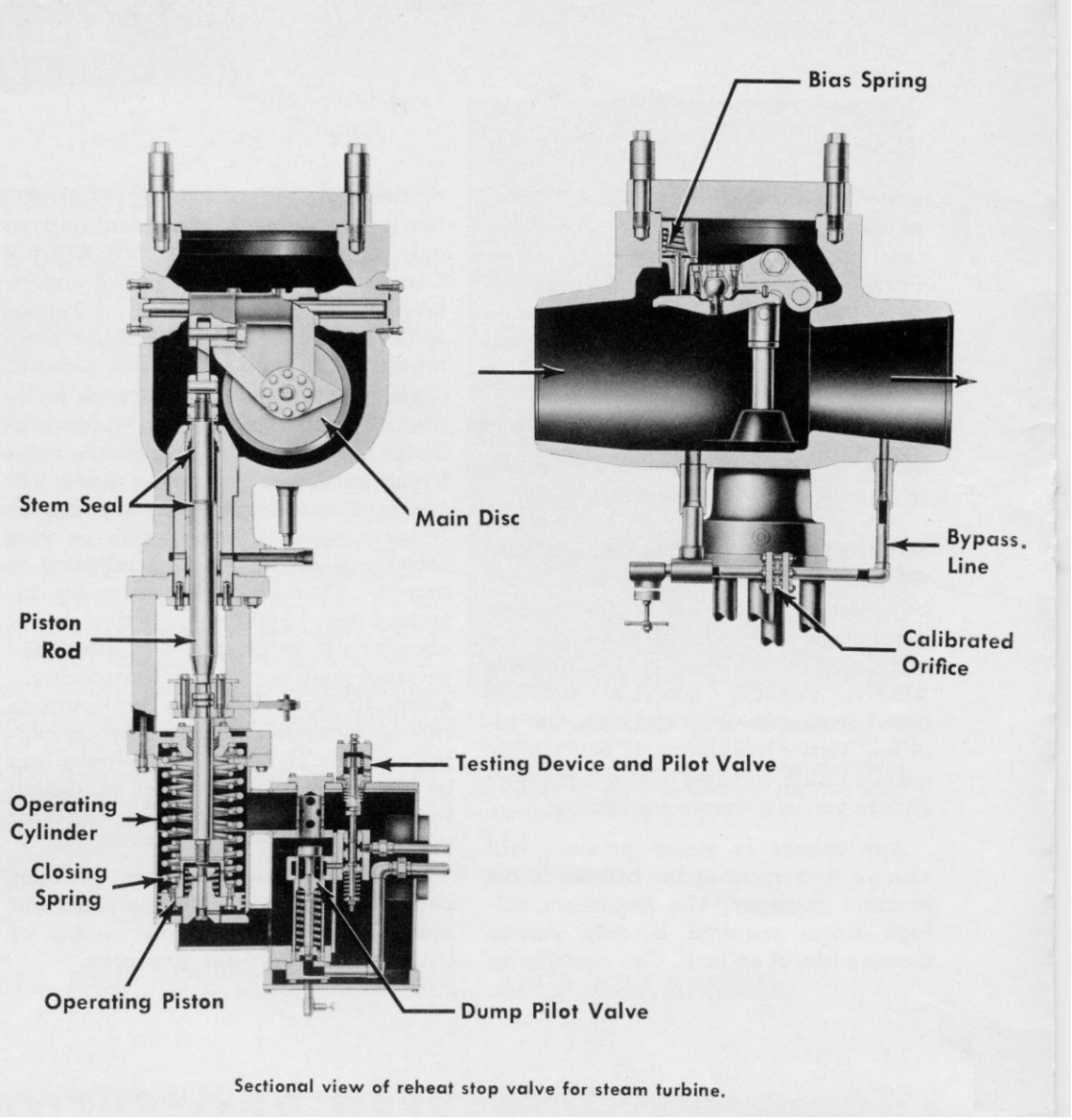



Figure 752. Reheat Stop Valve

The need for reheat stop valves has been recognized as the rapid development of reheat turbines entered a phase where a high percentage of the units had an overspeed potential in the reheater which was above a limit considered as safe. The ratio of rotor inertia to stored energy in the reheater becomes less favorable as larger units are built. Increased reheat pressure and the tendency to keep the pressure drop in the reheater small in order to improve station efficiency are also reasons for higher overspeed potentials of newer-design reheaters.

The energy stored in the reheater of an average boiler would be able to lift the corresponding turbine and generator rotor up approximately 2500 feet in the air within 15 seconds. This comparison gives a picture of the energies involved which would have to be dissipated if other means of second line protection against potential overspeed in the reheater were to be used.

Introducing losses by breaking the vacuum is practically ineffective because of the time required to fill the condenser with air and also because the energy which can be used by rotational losses in the short time available is comparatively small. Even immediate breaking of the vacuum would not introduce losses large enough to prevent the unit from reaching a dangerous speed. Testing of an automatic vacuum breaker valve during operation is impossible.

Dissipating a part of the stored energy by a house generator which is coupled to the main turbine shaft could reduce the peak speed by 5 to 10 percent assuming that the house generator would carry a constant load of about 6 to 8 percent of the turbine capability. However, a peak speed of 135 percent of rated which could still be reached would presumably trip most auxiliaries on overload thereby reducing this load appreciably and the top speed would still be above the safe limit speed. An electrical load cannot be used as an overspeed protection because many safety features are able to trip the corresponding breaker just at the moment when the load is most needed. Such a load does not fulfill the basic requirements of overspeed protection as stated in the first paragraph of "Protection Against Overspeed,"

Another method of dissipating the energy is to release a part of the reheat steam to the atmosphere or to the condenser through power—operated-relief valves as soon as the speed exceeds about 104 percent of rated. This is a method which could be relatively effective on older units, but on more recent designs the relief valve area would have to be very large and leakage problems become serious. Testing of power relief valves during operation will cause leakages sooner, and most power companies would not consent to test these valves at the required short intervals. The most serious problem, however, is the overstressing of the last high-pressure stage if the relief valves should open accidentally while the unit is carrying full load. If the power relief valves opened at full load, the reheat pressure at full steam flow would fall to approximately 30 to 50 percent of its normal value thereby increasing the loading of the last high-pressure stage to a dangerously high stress level.

Reheat stop valves which represent a conventional type of a second line of defense have been generally accepted since late 1952. The obvious advantages of this method of overspeed protection are:

1. The maximum speed after loss of full load and failure of the pre-emergency speed control is about 115 percent which is well within safe limits.

2. The valves can be tested to the fully closed position during normal operation at full load (on a few units only part load) without any inconvenient effect or increase of maintenance.

3. Tightness of the valves is not of fundamental importance. In fact an artificial leak across a calibrated orifice is necessary to balance the pressure across the valve to assure reopening after test to fully closed position.

4. Unlike the leakage losses of power relief valves, the losses of reheat stop valves are fully predictable and very small.

Compared with all other methods of secondary protections previously discussed and observed from a purely technical viewpoint, there is only one drawback to the reheat stop valves: the pressure drop.

The newest design of these valves which has been developed since 1952, however, has a practically negligible pressure drop. By studying the piping layout of a station carefully it is in many cases possible to keep the over-all pressure drop across the reheat system at the same value as it was on units without reheat stop valves.

The majority of the power companies have looked upon the decision to install reheat stop valves very favorably and these valves are now furnished on all new reheat turbines manufactured by the General Electric Company which have a high potential overspeed.
*Turbine -Generator Controls, Protections, and Accessories by G. W. Cunningham*

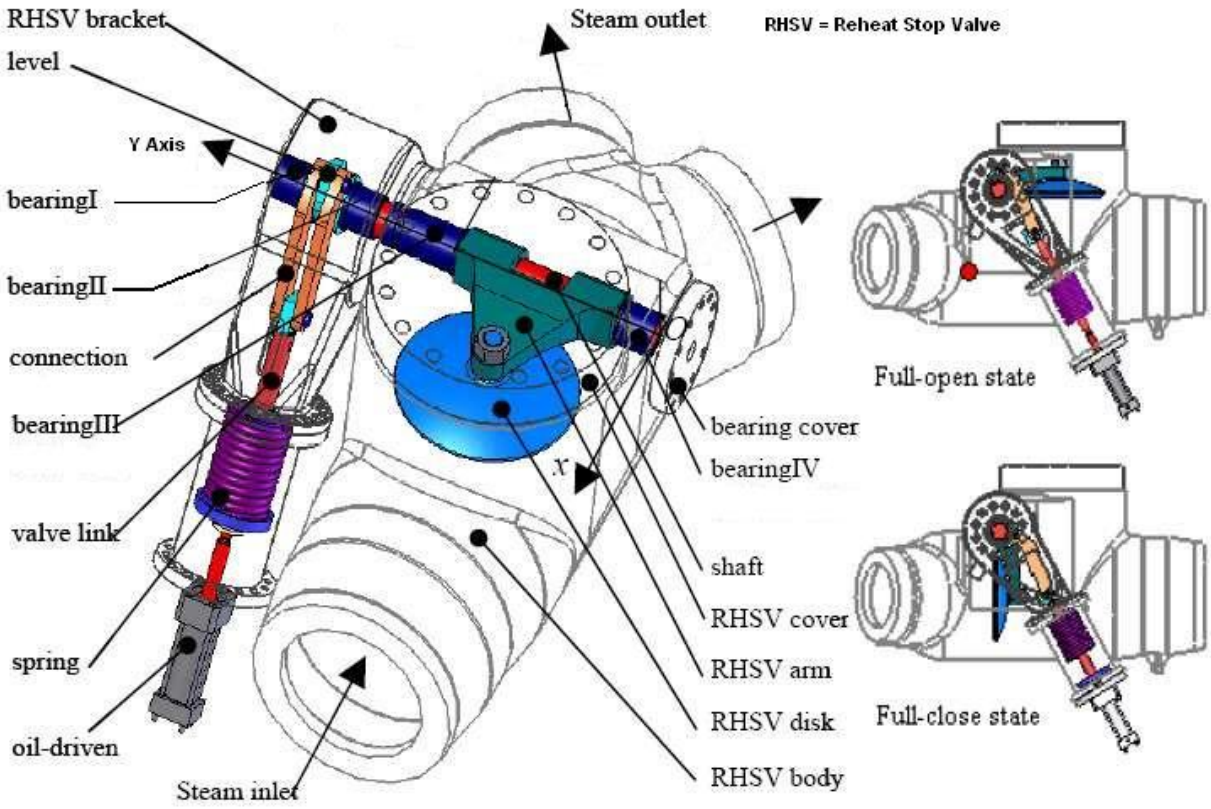



Figure 753. Reheat Stop Valve diagram

## 10. Describe an intercept control valve.

Whenever steam turbine reheating is employed, additional turbine protection is required. This protection is provided by a intercept valve, which is located in the steam line to the intermediate turbine and usually mounted on the turbine casing. Their purpose is to prevent excessive overspeeding of the turbine upon sudden loss of load due to the large volume of steam that is entrained in the reheat system.

In operation, the intercept valves are controlled by a pre-emergency governor which starts closing the valves whenever turbine speed exceeds 1% of normal. These valves are fully closed at 5% overspeed.

To make sure intercept valves are reliable, a means of testing them under load is provided. This is accomplished by having two (2) full-size hot reheat lines returning from the reheater to the intermediate turbine. An intercept valve in series with a back-up trip stop valve is installed each reheat line.

This permits exercising either intercept valve while the turbine is in operation with no loss of load to assure that it is functioning properly.

Usually dump valves are used with intercept valves. To relieve the steam trapped in the reheat section. The dump valves may discharge the steam to the atmosphere or reclaim it by dumping to the condenser.

*D.E.S.C. Modern Turbines pages 4 - 5*

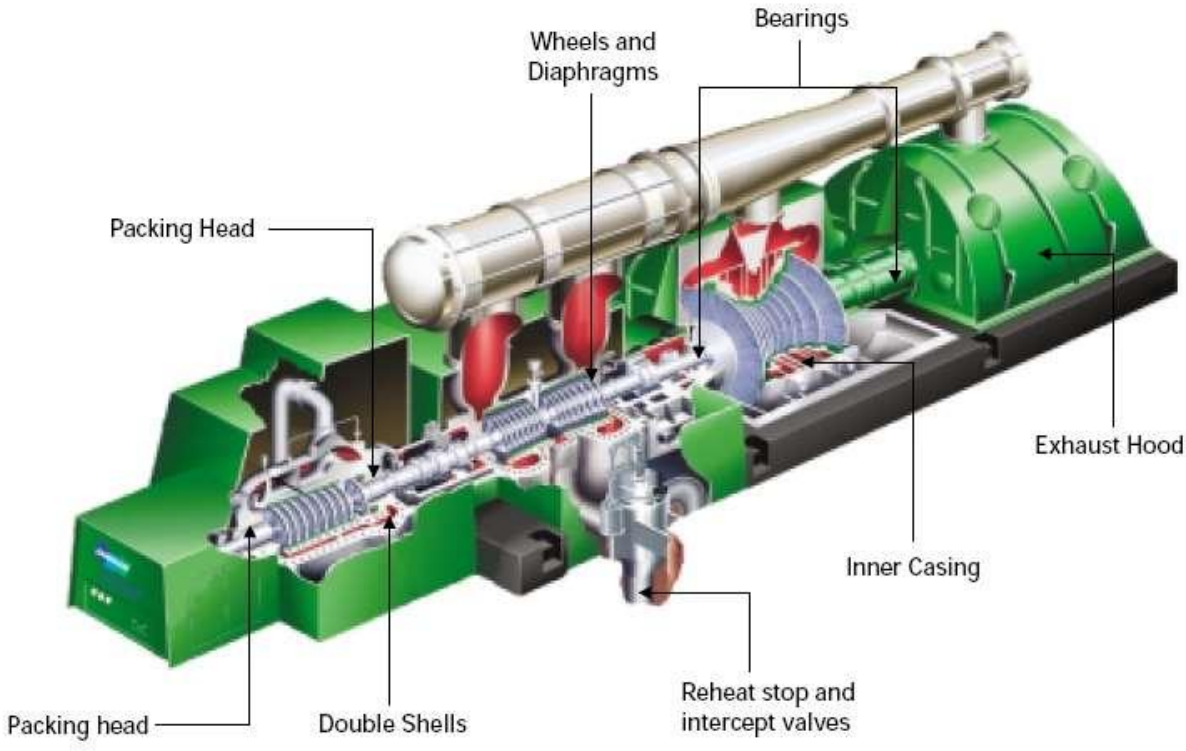



Figure 754. Location of Reheat Stop Valves and Intercept Valves on the turbine

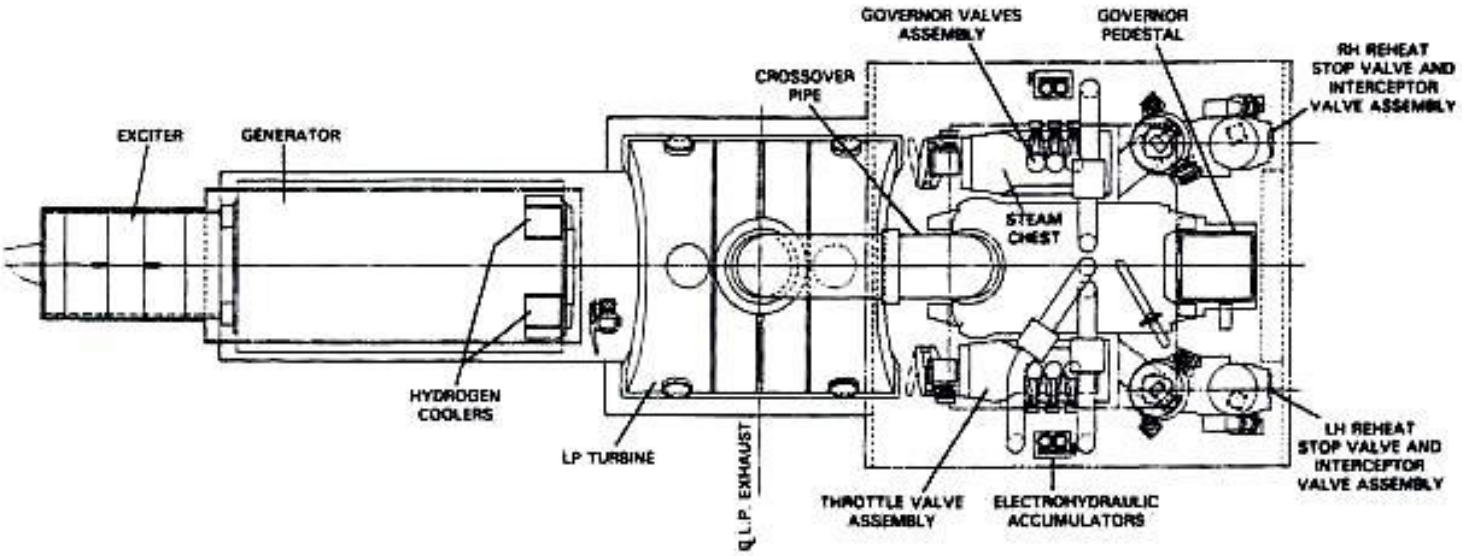



Figure 755. Two intercept valves are normally installed in a large turbine to allow one to be tested while the turbine is in operation

Figure 756. This photo shows two castings, each has one opening for a reheat stop valve and two openings for intercept valves.

Figure 757. Another casting with two intercept valve openings and one reheat stop valve opening.

# Chapter 24 Expansion and Vibration

## 1. How much does a turbine expand? Give an example. How are different expansions taken care of?

A turbine about 20 ft. long, with a 900 F. inlet temperature and 100 F. at the outlet, will expand about 5/8 in. over its length at room temperature.

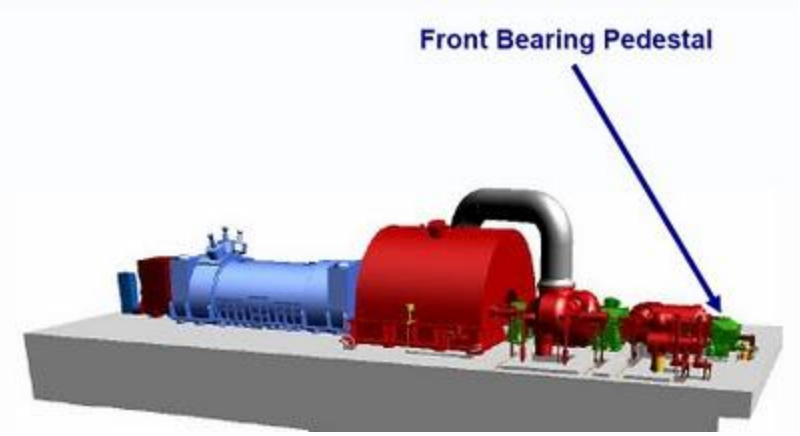



Figure 758.

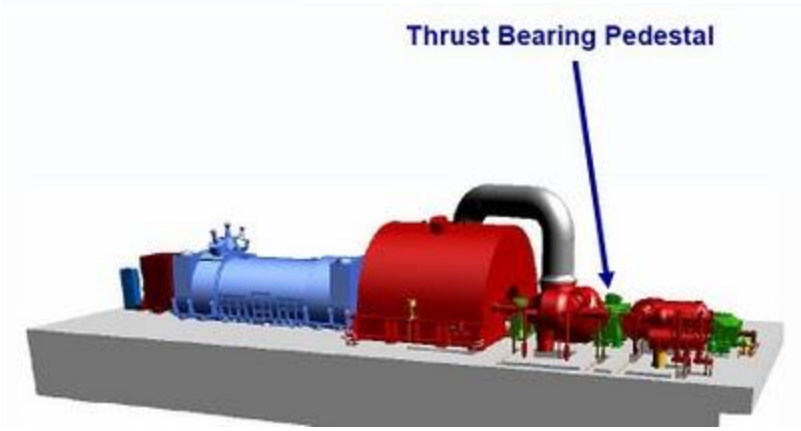



Figure 759.

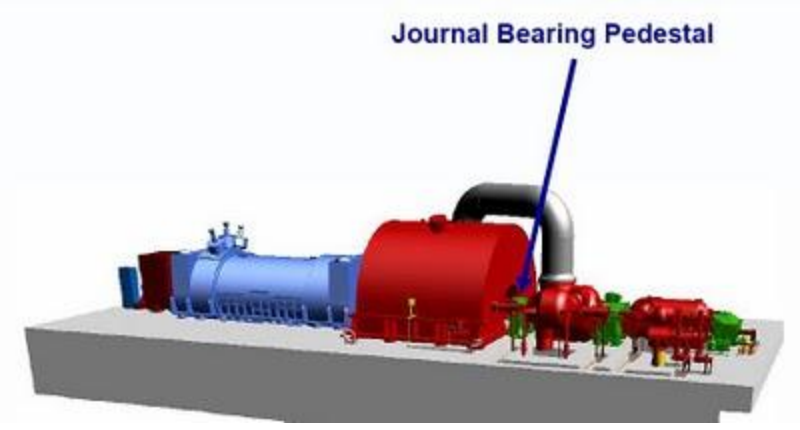



Figure 760.

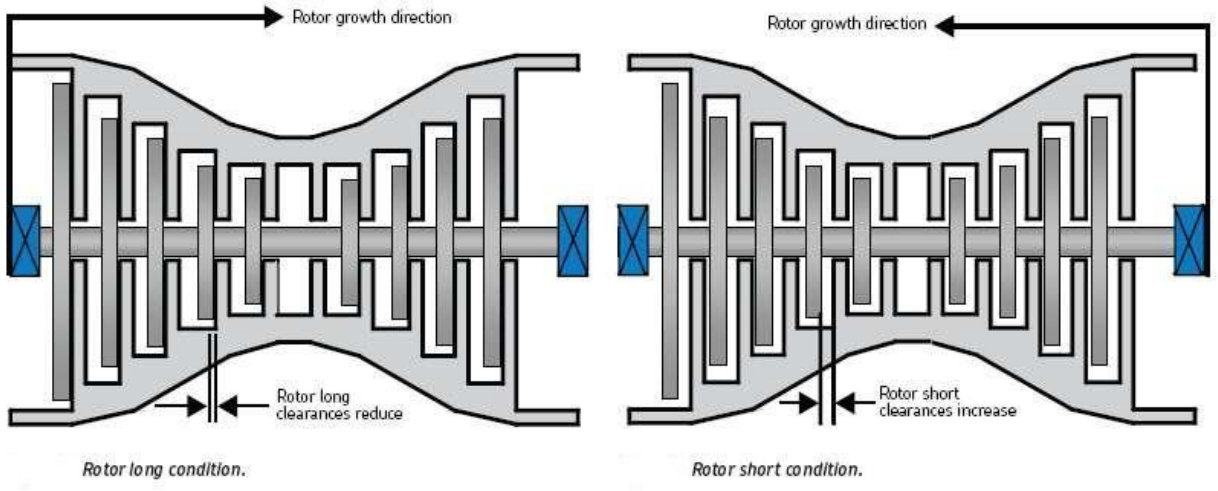



Figure 761. Differences in temperature during start-up cause rotor long and rotor short conditions

Axial differential expansion is usually allowed for by having a point of fixation between rotor and casing, near the hot end and by providing proper axial clearance between the stationary and rotating parts.

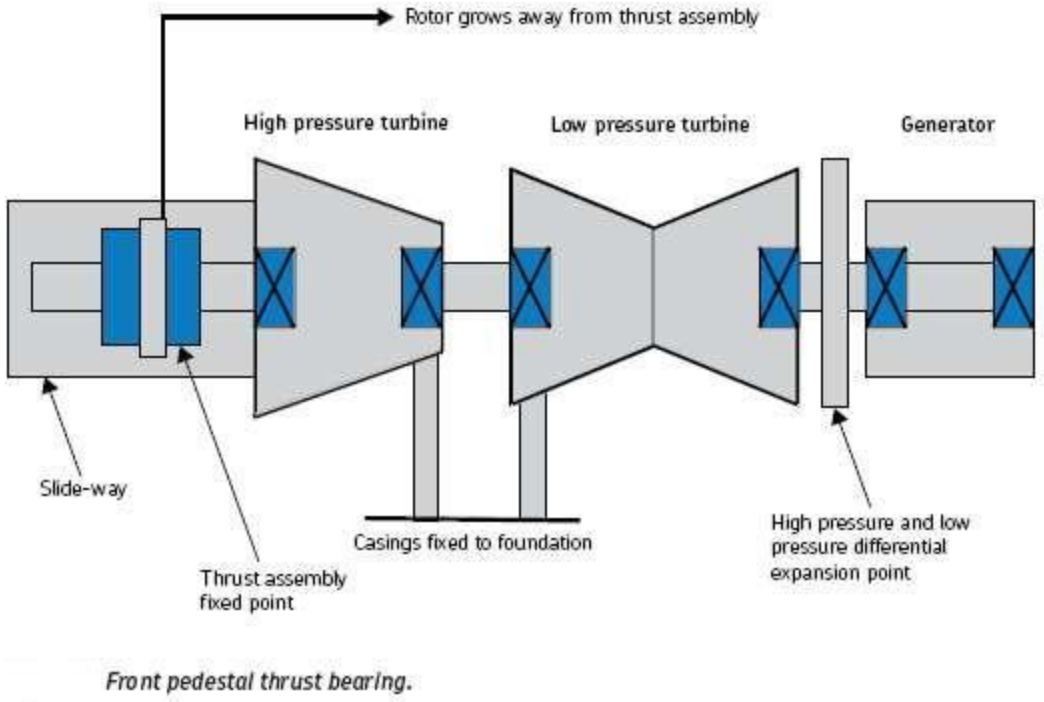



Figure 762. Casings and rotors grow away from their fixed points and must be considered when starting procedures are written.

Axial and transverse expansion of the casing is usually allowed for by keeping one end of the casing, usually the cold end, keyed to the foundation.

## 2. When does an unbalanced force become dangerous? What is this called?

An unbalanced force becomes dangerous when the speed of rotation is such that the unbalanced force passes a given point in the bearing with a frequency of the spinning rotor. This speed is known as the critical speed.

## 3. What is meant by critical speed?

It is the speed at which the machine vibrates most violently. It is due to many causes, such as imbalance or harmonic vibrations set up by the entire machine. To minimize damage, the turbine should be hurried through the known critical speed as rapidly as possible. (Caution, be sure the vibration is caused by critical speed and not by some other trouble).

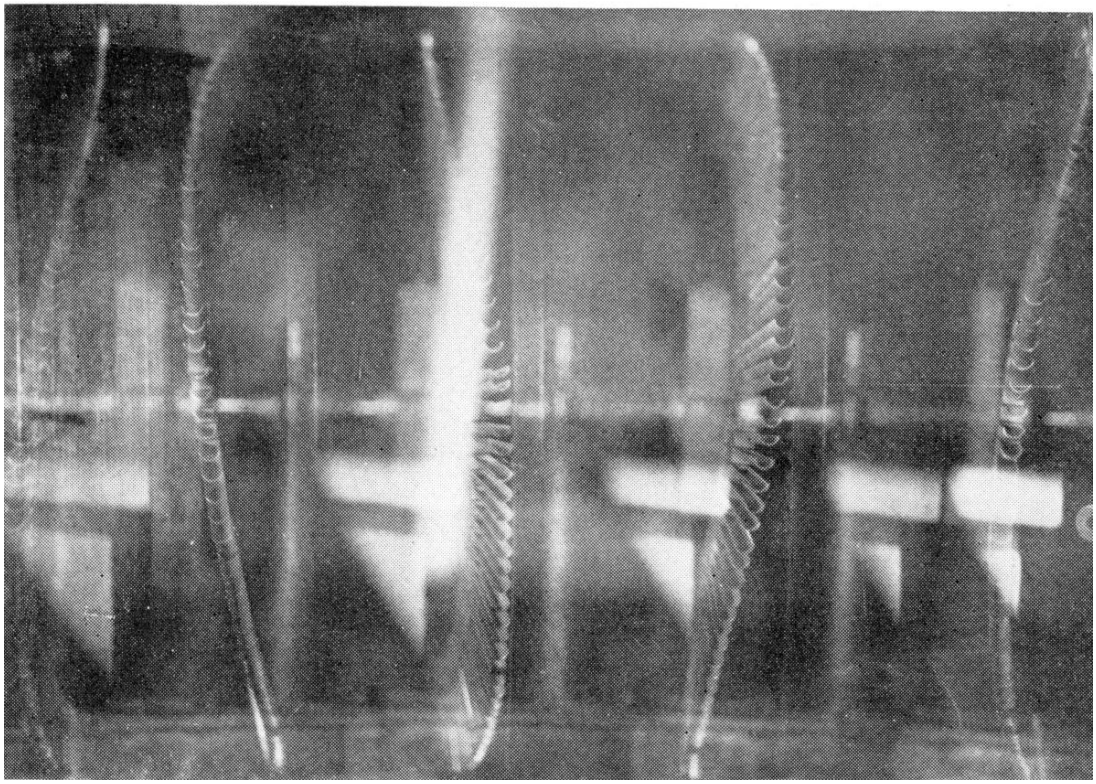


Figure 763. Five India rubber wheels spinning at their critical speed captured with a high speed photograph to show how violent the oscillations can become when something is rotated at its critical speed.

## 4. Explain critical speed. Is it the same for all turbines?

Critical speed is the speed at which the shaft vibration is greatest. The rotor because of its weight, deflects or bends, causing the center of mass and the true center line of the shaft to be out of line. If turbine is allowed to operate at critical speed it would vibrate to the point of destruction. As the speed is increased above the critical speed, the shaft begins to straighten and will once again revolve around its true center. It is very important when starting to pass through critical speed quickly.

The running and operating speed is usually 15% above the calculated critical speed for those turbines with flexible shafts and 25% below critical speed for those with stiff shafts. This statement taken from Edison Turbine Operations Section shows that all turbines DO NOT have the same critical speed. The critical speed will vary with length, shaft diameter and points of support.

*D.E.S.C. Boiler Operations page 18*

*S&V page 122 & 123*

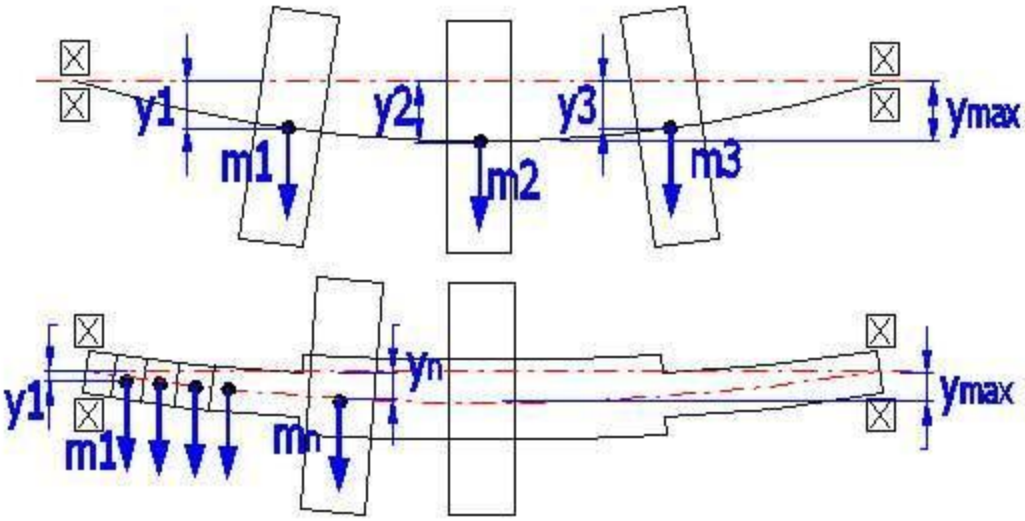



Figure 764. Shows how a turbine shaft can bow

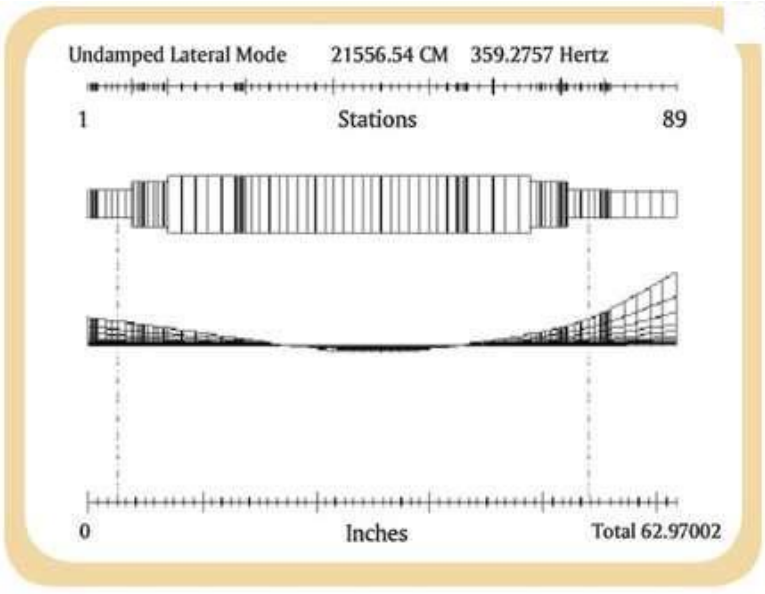



Figure 765. Graph of first critical speed

## 5. Do turbines have more than one critical speed? In relation to this critical speed, at what speed do modern turbines run?

Yes, the second critical speed is at twice the RPM of the fundamental, the third at three times, etc. Modern turbines are designed to operate normally between their fundamental and second critical speeds.

## 6. Why not operate turbines below their critical speed?

Turbines are not operated below critical speed because this would require such heavy rotor construction to achieve the necessary stiffness. This would make the machine unduly expensive and bulky.

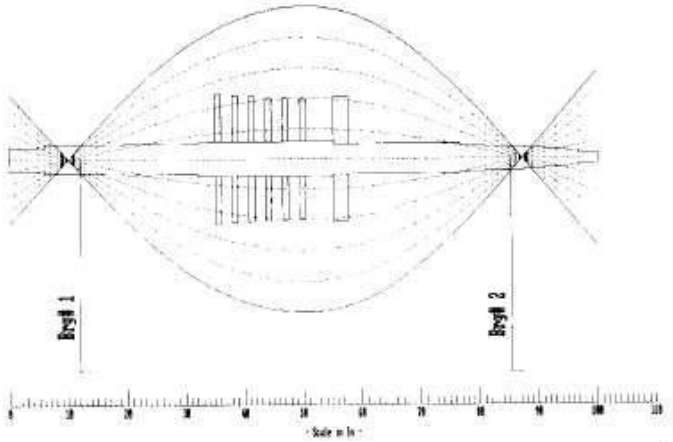



Figure 766. *Critical Speed Mode Shape for Original Rotor and Five-Pad Tilting Pad Bearings.*

## 7. Can you have more than one (1) critical speed on a turbine shaft?

Yes. All flexible structures will vibrate at certain frequencies.

Critical speed is the speed at which the shaft vibration is greatest. Because of its weight the shaft deflects or bends causing vibration.

There may be any number of critical speeds. The second occurs at twice the first and the third at three times the first and so on. Modern turbines operate between first and second critical speeds.

Running speeds of all turbines are 30% above or below critical speed. If the critical speed figures out only slightly above running speed the shaft is made longer and stiffer thereby raising critical speed.

*D.E.S.C. Turbine Operation page 18*

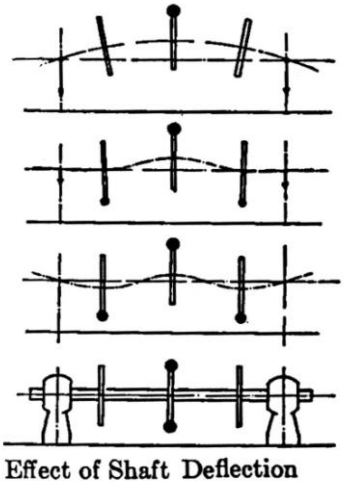



Figure 767.

As every horizontal rotor deflects somewhat under its own weight, it is never possible to have the center of mass and the true center line of the shaft coincide. As the rotor speeds up this eccentricity of mass results in an increasing centrifugal force tending to bend the shaft. Any slight unbalancing in the mass aggravates this condition. At a certain speed this unbalanced centrifugal force neutralizes the elasticity of the shaft which resists deflection. The shaft deflection progressively increases, and if unrestrained, failure would result. The speed causing indefinitely large deflection of the rotor for a small initial eccentricity is the critical speed of the shaft. If the speed is increased above the critical speed, the shaft begins to straighten and tends to revolve about its true center of mass. Operation may be very smooth under these conditions, although other critical speeds may be encountered at still higher speeds. If the critical speed of a rotor is at 1300 rpm a critical speed will be realized at twice that speed and a third at three times that speed and so on.

*Kents 11th Edition. page 8-38.*

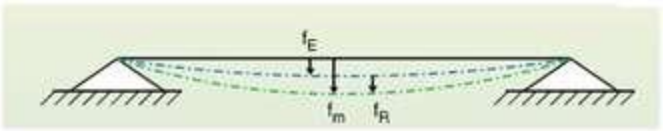



Figure 768. Rotor bowing due to weight of shaft

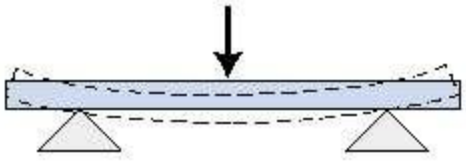


Figure 769. Rotor bowing due to weight of shaft

## 8. A turbo generator with a flexible shaft operates faster or slower than its critical speed?

Critical speed is the speed at which the shaft vibration is the greatest. The rotor, because of its weight deflects or bends, causing the center of mass and the true center line of the rotor to be out of line. Some turbines operate above their critical speeds and in starting pass quickly through this range to lessen the serious effects of vibration. The running or operation speed is usually about 15% above the calculated critical speed for these turbines or those with flexible shafts, and 25% below critical speed for those with stiff shafts. Croft says a turbine shaft is said to be stiff if it is designed to operate under its fundamental critical speed.

A turbine shaft is said to be flexible if it is designed to work somewhere over its fundamental critical speed.

*D.E.S.C. Turbine Operation page 18*

*Croft Turbines page 87*

## 9. How is expansion in large turbines taken care of?

Large turbines are normally connected rigidly at the low pressure end where it connects to the condenser. The point of connection between the rotor and the casing is at the thrust bearing at the high pressure end. As the turbine casing expands toward the high pressure end, it slides on a flat piece of metal on the front pedestal called a slideway or sole plate that allows the turbine to move back and forth without allowing it to move side to side. This must be kept lubricated by a special slideway lubricant.

## 10. How does a turbine expand?

Turbines are anchored to the foundation at the exhaust end and allowed to expand towards the inlet end as they heat up. The front of the turbine is normally supported on a flat plate and slides on the plates as the unit expands and contracts. Steam pipes are connected through long easy bends with flexibility great enough not to place strain on connecting flanges.

The common fixed point between the rotor and the casing is the thrust bearing. The rotor expands toward the low pressure end.

*S&V page 81-85, Kents 11th Edition. page 8-52, 8-53*

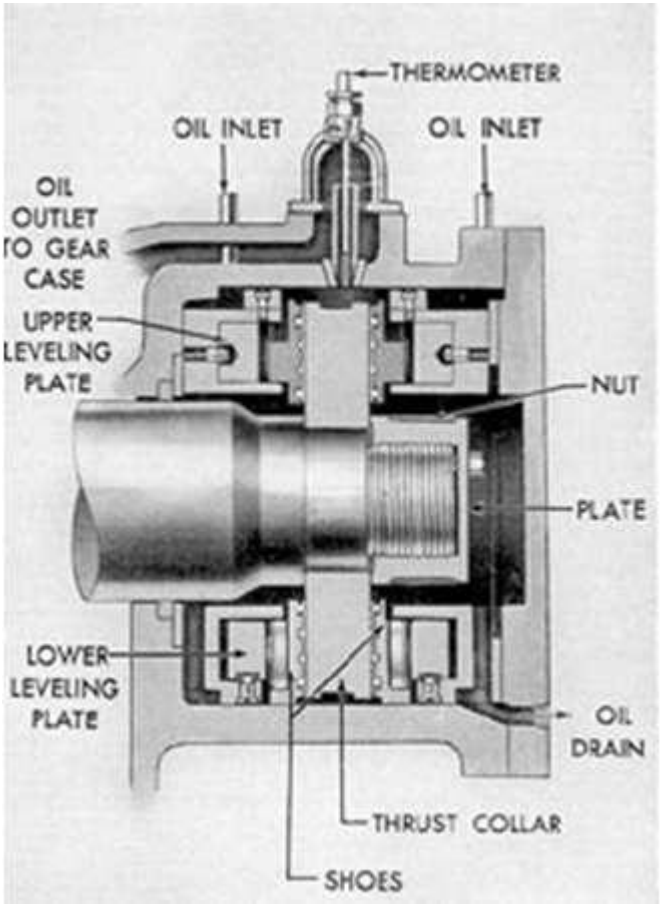



Figure 770. Expansion occurs from the thrust collar. It is the point at which the rotor and casing are connected together.

## 11. What must turbine designers be careful of, as concerning expansion?

Designers must control the shape and thickness of all parts so that they will tend to expand or contract equally in the same direction with changing steam temperatures. Clearances must be maintained while turbine parts enlarge their dimensions with temperature increase.

## 12. What is a "node"?

A point with no vibration which appears midway between the points of support is called a "node".

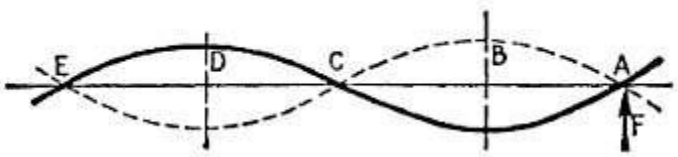



Figure 771. “C” is the node point

## 13. How can problems of "excessive vibration or noise" due to piping strain be avoided on steam turbines?

The inlet as well as exhaust steam lines should be firmly supported to avoid strains from being imposed on the turbine.

Adequate allowance should be made for expansion of steam pipes due to heat

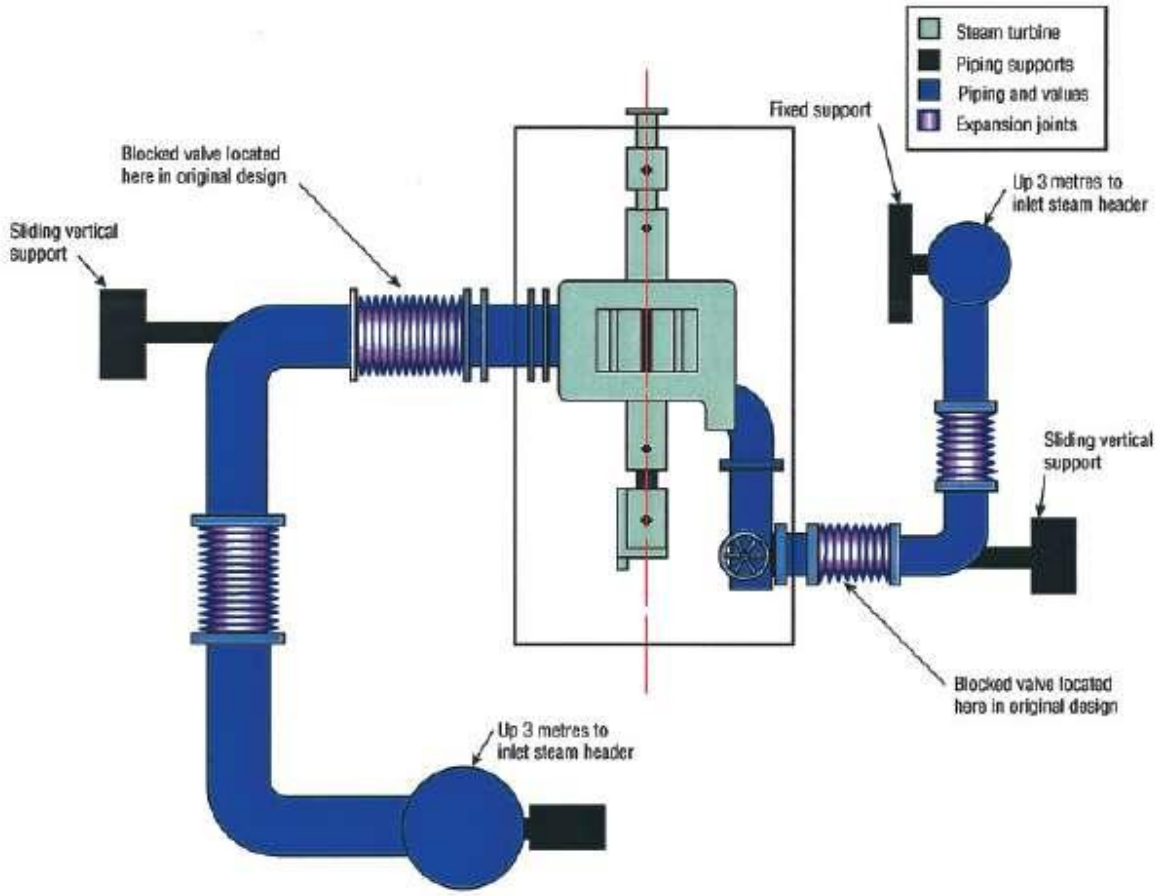

Steam turbine
Piping supports
Piping and values
Expansion joints
Fixed support
Blocked valve located here in original design
Up 3 metres to inlet steam header
Sliding vertical support
Sliding vertical support
Blocked valve located here in original design
Up 3 metres to inlet steam header

Figure 772. Expansion joints so that no strain is placed on the turbine

Figure 773. *Flexible steal-beam foundation for earthquake protection*

## 14. What causes a turbine to vibrate?

Turbines will vibrate due to the fact that the metals are not homogeneous (uniform throughout their mass). In addition, all metals will exhibit a certain amount of flexibility.

## 15. What are the main causes of turbine vibration?

unbalanced parts

poor alignment of parts

loose parts

rubbing parts

lubrication troubles

steam troubles

foundation troubles

cracked or excessively worn parts

**16. What are the possible causes of excessive vibration or noise in a steam turbine?**

Misalignment.

Worn bearings.

Worn coupling to driven machine.

Unbalanced coupling to driven machine.

Unbalanced wheel.

Piping strain.

Bent shaft.

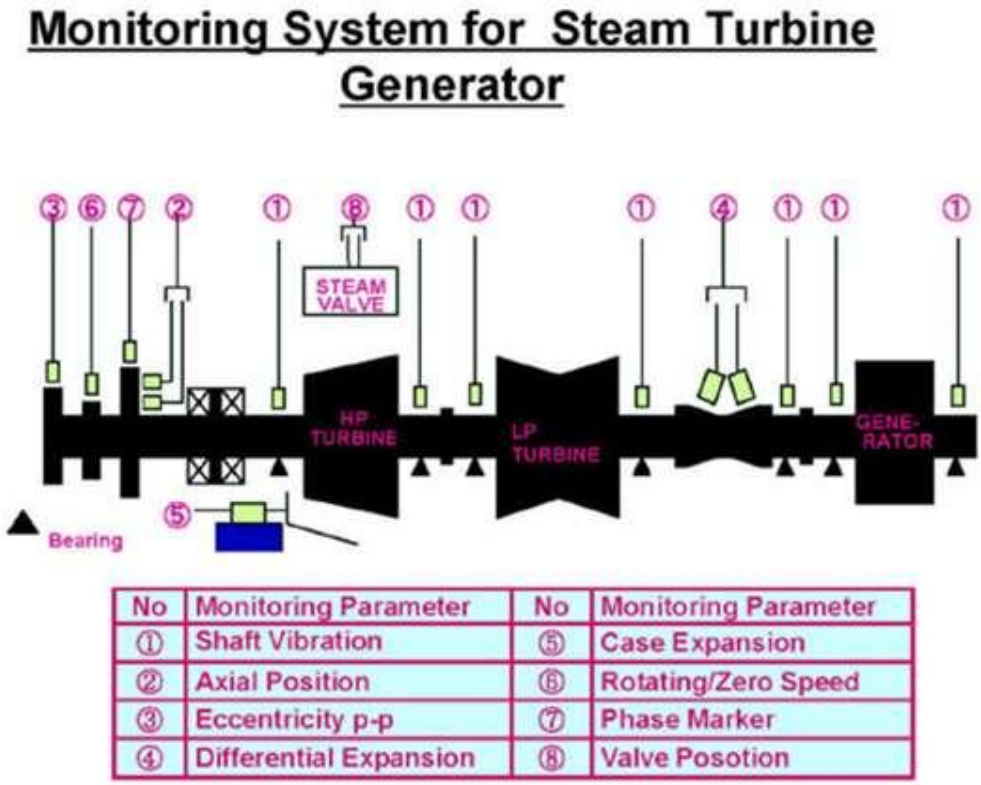

Monitoring System for Steam Turbine Generator
③ ⑥ ⑦ ② ① ⑧ ① ① ① ④ ① ① ①
STEAM VALVE
HP TURBINE
LP TURBINE
GENE-RATOR
⑤
Bearing
No | Monitoring Parameter | No | Monitoring Parameter
① | Shaft Vibration | ⑤ | Case Expansion
② | Axial Position | ⑥ | Rotating/Zero Speed
③ | Eccentricity p-p | ⑦ | Phase Marker
④ | Differential Expansion | ⑧ | Valve Posotion

Figure 774. Monitoring points to make sure the turbine is operating correctly

## 17. What is the most common cause of turbine vibration?

Warming up a turbine too quickly

Other common causes of vibration are:

1. Worn bearings
2. Vibration due to unbalanced weight in turbine.
    A) Broken, eroded, or corroded blades.
    B) Bent shaft.
    C) Distortion due to unequal heating.
    D) Scale deposits on the blading.
3. Improper alignment of the rotor to the coupler.
    A) Improperly aligned upon installation.
    B) Foundation settling.
4. Water coming over from boiler.
5. Loose or worn thrust collar.
6. Misaligned governor drive.
7. Vibration caused by generator.
    A) Unequal air gap on loose coils in the starter.
    B) Phase unbalance in the generator.

*W&L page 496, D.E.S.C. Turbine Operation page 12*

## 18. What is "torsional vibration"? Why don't we worry about this phenomenon?

Torsional vibration is when the shaft twists in one direction, untwists, and then twists in the other direction while it rotates. No trouble has ever been reported from this phenomenon.

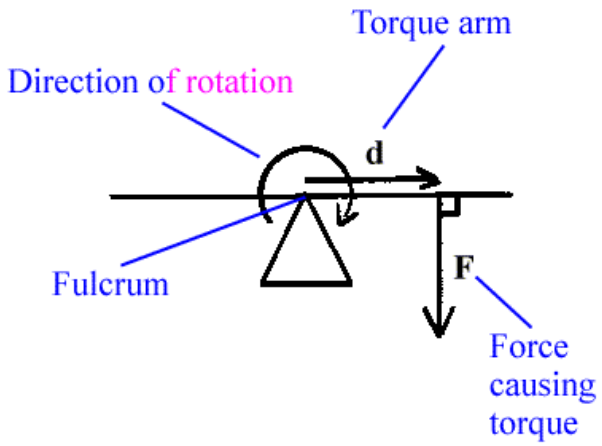



Figure 775. torsional vibration

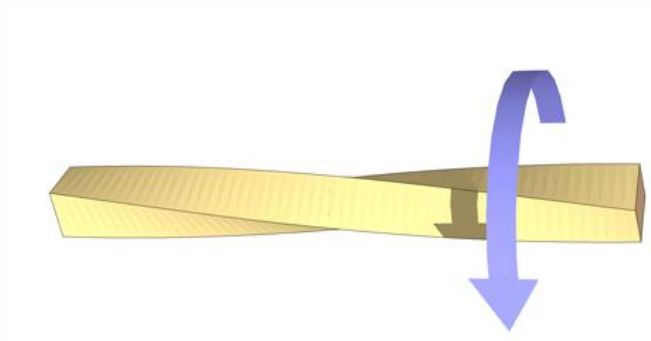


Figure 776. Torsional vibration

Figure 777. Bentley Nevada is the standard monitoring system for large turbines

Figure 778. Monitoring the Bentley Nevada 3500

| 3500 Series Measurement Capabilities | 3500/25 | 3500/40M | 3500/42M | 3500/44M | 3500/45 | 3500/46M | 3500/50 | 3500/53 | 3500/60,/61,/6 | 3500/62 | 3500/63 | 3500/64M | 3500/70M | 3500/72M | 3500/77M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measurements | | | | | | | | | | | | | | | |
| Phase reference | ● | | | | | | | | | | | | | | |
| Radial vibration (proximity probes) | | ● | ● | | | | | | | | | | | | |
| Radial position (proximity probes) | | ● | ● | | | | | | | | | | | | |
| Axial position (proximity probes) | | ● | ● | | ● | | | | | | | | | | |
| Eccentricity (proximity probes) | | ● | ● | | | | | | | | | | | | |
| Seismic vibration (velocity transducers / accelerometers) | | | ● | | | | | | | | | | | | |
| Shaft absolute (proximity and seismic) | | | ● | | | | | | | | | | | | |
| Aeroderivative gas turbine casing vibration | | | | ● | | | | | | | | | | | |
| Differential expansion | | ● | ● | | ● | | | | | | | | | | |
| Ramp differential expansion | | | | | ● | | | | | | | | | | |
| Complementary differential expansion | | | | | ● | | | | | | | | | | |
| Case expansion | | | | | ● | | | | | | | | | | |
| Valve position | | | | | ● | | | | | | | | | | |
| Hydro turbine/generator vibration | | | | | | ● | | | | | | | | | |
| Hydro generator air gap | | | | | | ● | | | | | | | | | |
| Machine operating state (discrete input)[1] | | | | | | ● | | | | | | | | | |
| Rotor speed | | | | | | | ● | | | | | | | | |
| Rotor speed rate-of-change (acceleration) | | | | | | | ● | | | | | | | | |
| Rotor zero speed (turning gear engagement) | | | | | | | ● | | | | | | | | |
| Reverse rotation | | | | | | | ● | | | | | | | | |
| Overspeed | | | | | | | | ● | | | | | | | |
| Temperature (direct/average/differential)[2] | | | | | | | | | ● | | | | | | |
| Process variable signals (4-20 mA, 1-5 vdc, etc.) | | | | | | | | | | ● | | | | | |

Figure 779. Some of the points monitored by the Bentley Nevada 3500

# Chapter 25 Protective Equipment and Instruments

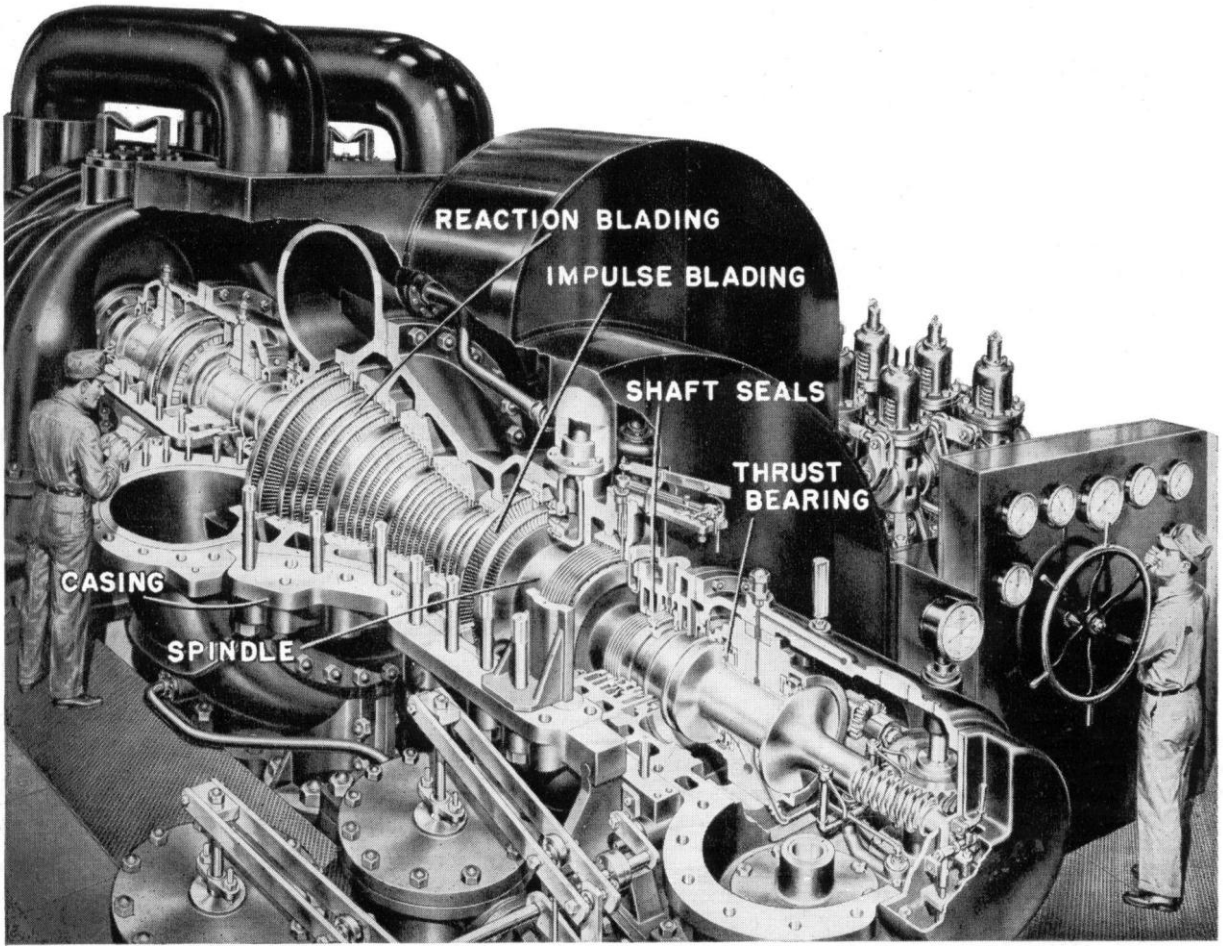



Figure 780. Steam Turbine Operator checking instruments on the front standard of the turbine

## 1. Name the protective equipment used on a turbine

Various forms of protective equipment commonly used on turbines are:

1) Overspeed governor

2) Low oil pressure

3) Rotor end travel

4) Low vacuum

5) Reverse current.

6) Hood sprays

**2. Name types of meters used on a turbine**

There are a large number of meters on a turbine-generator, below are a list of the five most common:

1) RPM meter.

2) Oil pressure/ temperature indicator

3) Spindle-eccentricity meter.

4) Differential-expansion meter.

5) Vibration

*Steam Turbines. Power Reprint. June 1962. page s-31*

**3. Explain the different types of instruments used in turbine operation.**

Instruments used in turbine operation include:

1. Pressure gauges to indicate the state of the steam at various points. Also, for oil pressure to bearings and governor system.

2. Thermometers to determine temperature of steam at various points. Also for oil temperatures.

3. Tachometer to indicate speed of rotor.

4. In addition, meters that measure shaft eccentricity, bearing vibration, cylinder axial expansion, and noise meters.

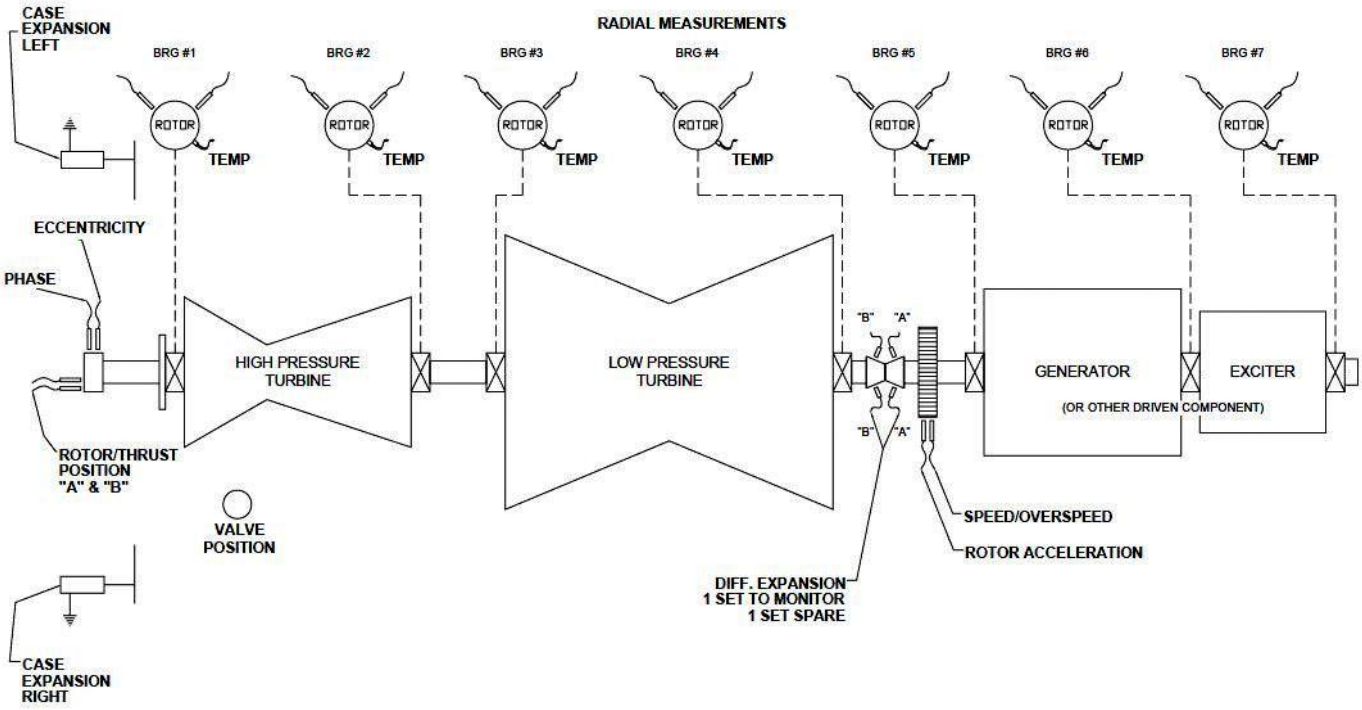



Figure 781. Instrument sensor locations on the turbine

**4. Explain how a reed tachometer functions.**

A reed tachometer is a device that uses the frequencies of the equipment to determine the speed. In the past, the use of high tech methods of determining speed were not available. A rotor spinning at a specific rpm will transmit a specific frequency, that frequency may be mathematically calculated, a piece of flat stock is machined to have tines of different sizes that vibrate at different speeds. When the center tines are vibrating the operating speed has been reached.

*George Brown. Shift Engineer. Mistersky Power Station*

Figure 782. Standco Reed Tachometer

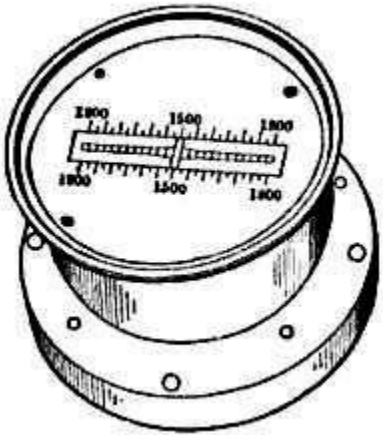


Figure 783. Another style of reed tachometer

## 5. Describe Turbine Supervisory Instruments

The following supervisory instruments are furnished with the turbine unit and are to be observed during start-up, operation and shutdown.

1) - Casing Expansion
As a unit is taken from its cold condition to its hot and loaded state, the thermal changes in the casings will cause it to expand. The Casing expansion scale measures the movement of the force pedestal relative to a fixed point (the foundation). It indicates expansion and contraction of the casings during starting and stopping period, and for changes in load, steam temperatures. Should it fail to indicate during these transient conditions, the situation should be investigated? The relative position of the fore pedestal should be essentially the same for similar conditions of load, steam conditions, vacuum, etc.

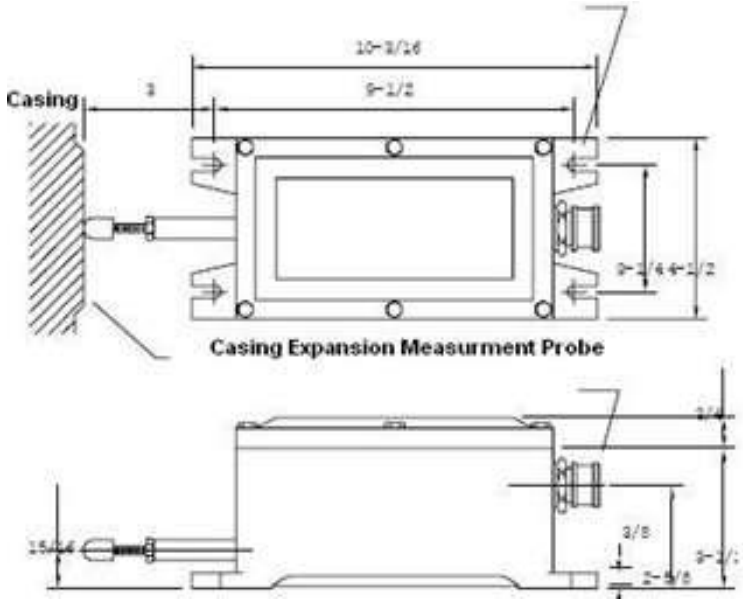



Figure 784. Casing Expansion monitor

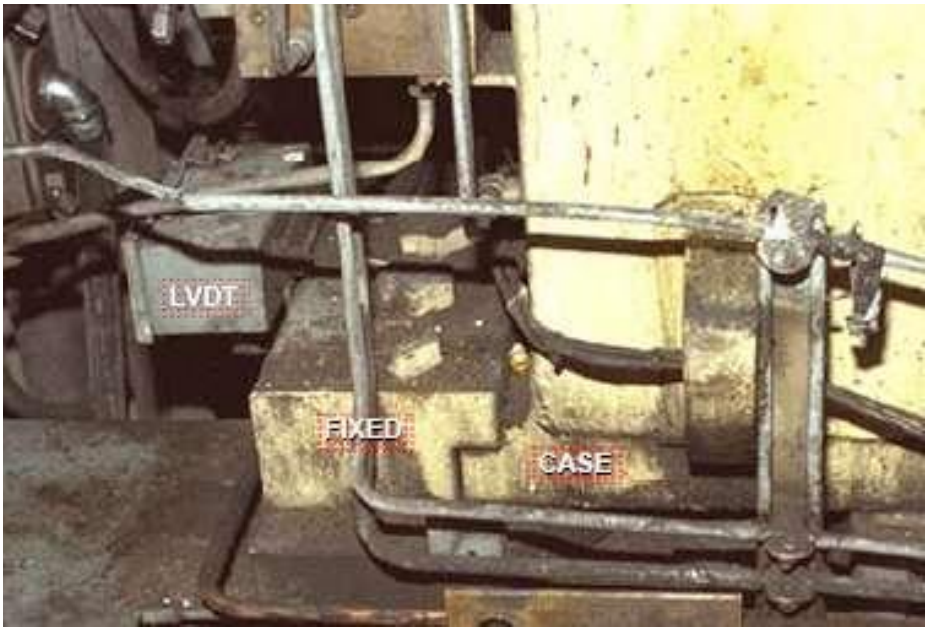



Figure 785. Casing expansion monitor mounted on fixed point at LVDT

2) - Rotor Position

Rotor Position instrument measures the relative axial position of the turbine rotor thrust collar with respect to the first bearing support. The thrust collar exerts a pressure against the thrust shoes, which are located on both sides of the thrust collar. Wear on the thrust shoes results in an axial movement of the rotor and is indicated on these instruments. This instrument is equipped with an alarm relay which activates if the rotor moves beyond a predetermined distance. Continued movement beyond a second predetermined distance activates rotor position trip relay which trip the turbine via the emergency trip system.

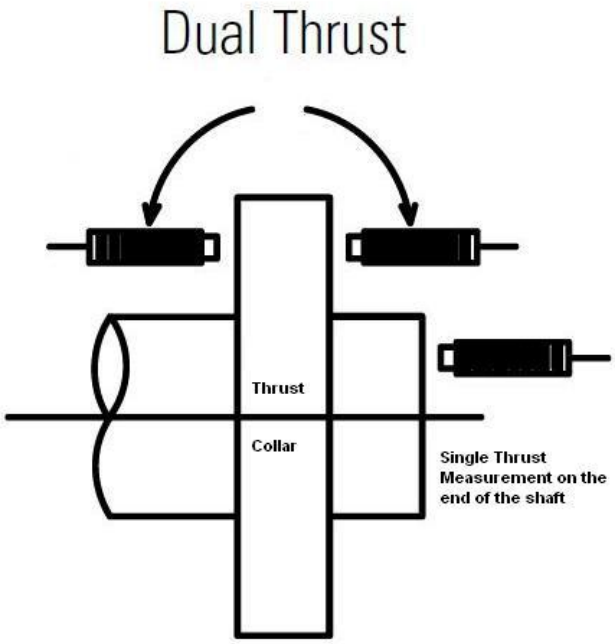



Figure 786. Thrust collar position sensors

Thrust position indication includes one or two Eddy Probe Systems to observe the position of the thrust collar within its bearings. This system is an internal installation and need not replace the existing system because many original installations utilize a differential pressure system that interfaces with the turbine hydraulic control system.

3) - Differential Expansion

When steam is admitted to a turbine, both the rotating parts and the casings will expand. Because of its smaller mass, the rotor will heat faster and therefore expand faster than the casings. Axial clearances between the rotating and the stationary parts are provided to allow for differential expansion in the turbine, but contact between the rotating and stationary parts may occur if the allowable differential expansion limits are exceeded. The purpose of the differential expansion meter is to chart the relative motion of the rotating and stationary parts. It gives a continuous indication of the axial clearance while the turbine is in operation. The instrument is equipped with alarm relay which activates if the value reaches the alarm point. As the rotating and stationary parts become equally heated after a transient condition, the deferential expansion will decrease.

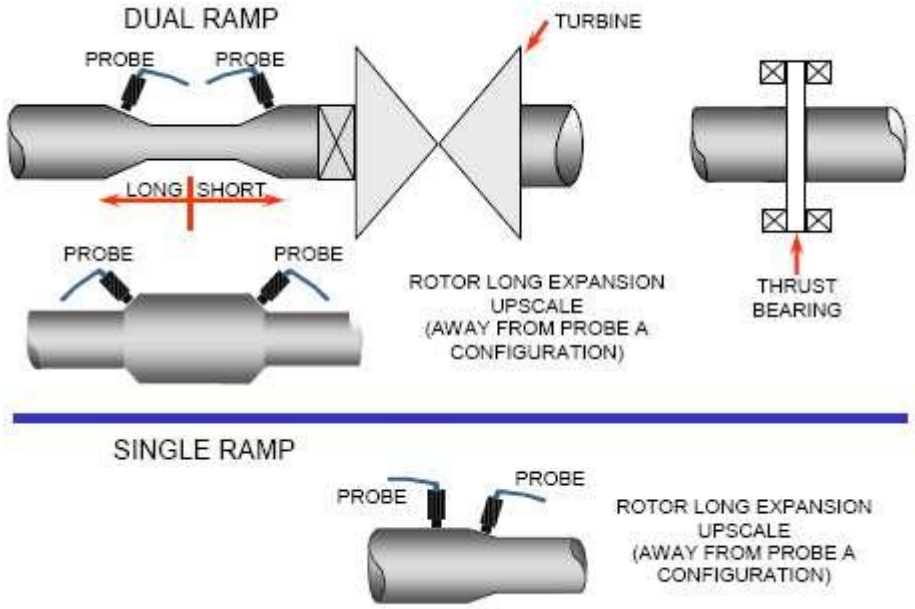



Figure 787. Differential expansion probes

Figure 788. Differential expansion probes in location on the turbine

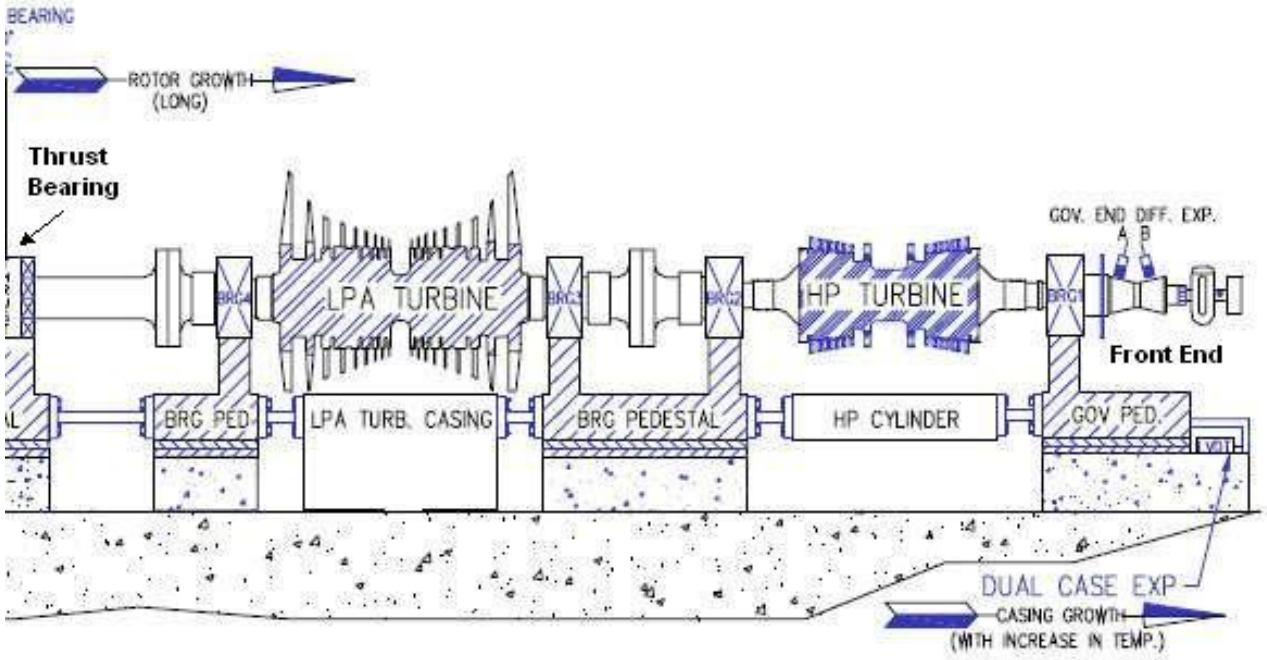



Figure 789. The front end half of half large turbine expansion diagram

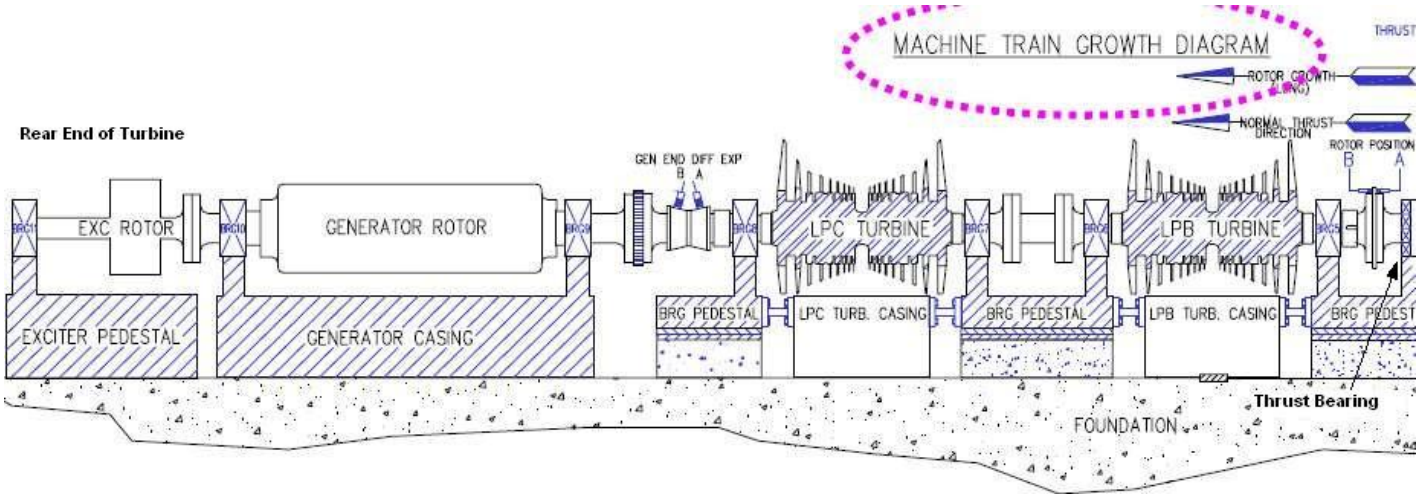
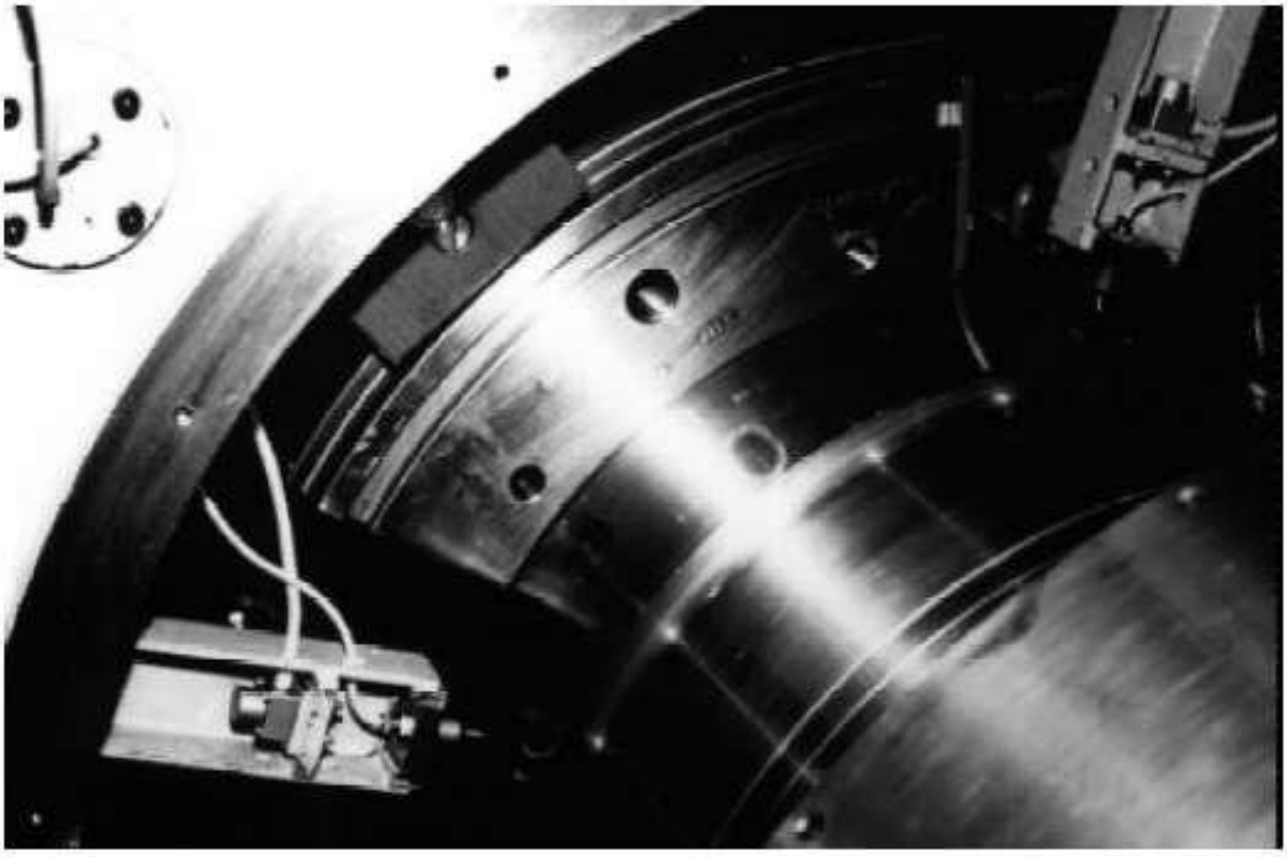



Figure 790. The rear end half of large turbine expansion diagram

This picture is so long it had to be broken into two parts to fit it on the page. This picture illustrates the differential expansion of the casing versus the rotor. The front of the turbine is at the right hand side of the top picture at the high pressure end. The fixed point between the rotor and the casing is the thrust bearing of which half is shown at the extreme left of the upper picture and is continued at the extreme right of the lower picture. The rotor and the casing grow in both directions from the thrust bearing which is located in the approximate center of this particular turbine of extreme length. It is referred to as a “train” because of the length of the connected casings.

4) -Vibration

The vibration instrument is used to measure and record vibration of a turbine rotor at speeds above 600rpm. Below this speed, the rotor bowing is recorded as eccentricity. The vibrations are measured on the rotor near the main bearings. Excessive vibrations serve as a warning for abnormal and possible hazardous conditions in the turbine. Each vibration instrument is equipped with alarm and trip relays which activates when excessive vibrations are measured at any one of the bearings.



Mounting of accelerometers and proximity transducers to measure absolute shaft vibration

Figure 791.

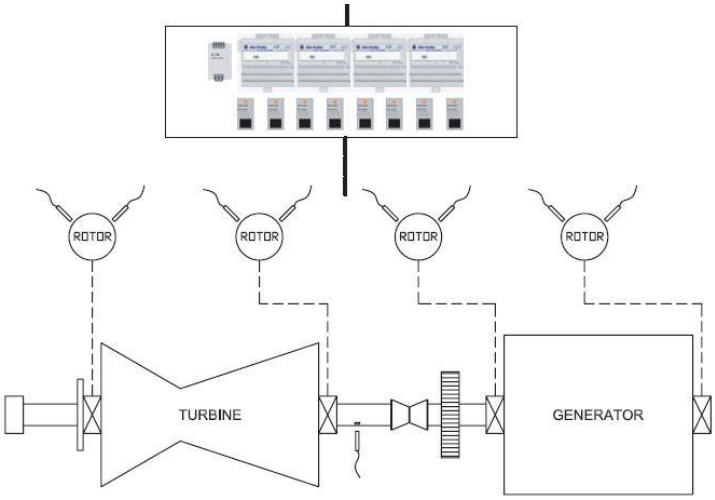



Figure 792. Vibration Monitors on the shaft

5) - Rotor Eccentricity

When a turbine has been shut down, the rotor will tend to bow due to uneven cooling if the upper half of the casing enclosing the rotor is at a higher temperature than the lower half. By rotating the rotor slowly on turning gear, the rotor will be subjected to more uniform temperature, thereby minimizing bowing.

This bowing of the rotor is recorded continuously as eccentricity from turning gear speed to approximately 600 rpm. The eccentricity instrument is equipped with an alarm signal which activates when the eccentricity reaches the alarm point.

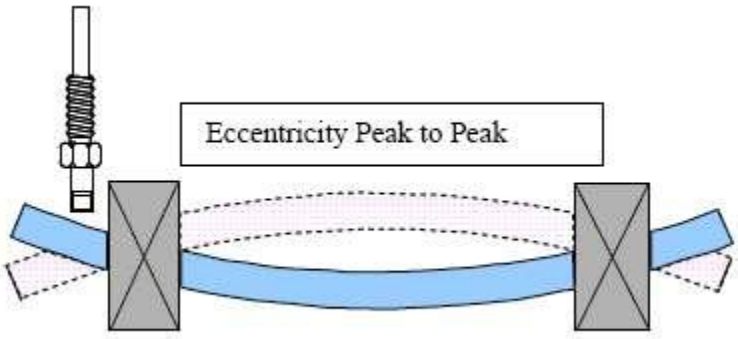



Figure 793. Eccentricity monitor

A rotor which has been sitting idle during overhaul or has been inadvertently stopped during coast-down for an extended period will develop a bow or bend. This condition must be corrected by turning gear operation and, possibly, with auxiliary heating prior to high speed operation to prevent internal clearance rubbing.

Eccentricity systems installed by OEMs monitor the turbine stub shaft or a shaft collar using induction coils. A retro-fit Eddy Probe system will monitor the same location and many times use the same brackets.

6) - Valve Position. Correct valve positioning is required to efficiently operate a steam turbine. Some turbines may require several throttle valves be monitored and some turbines will add instrumentation to the main stop valve(s) to determine when they lift from their seats.

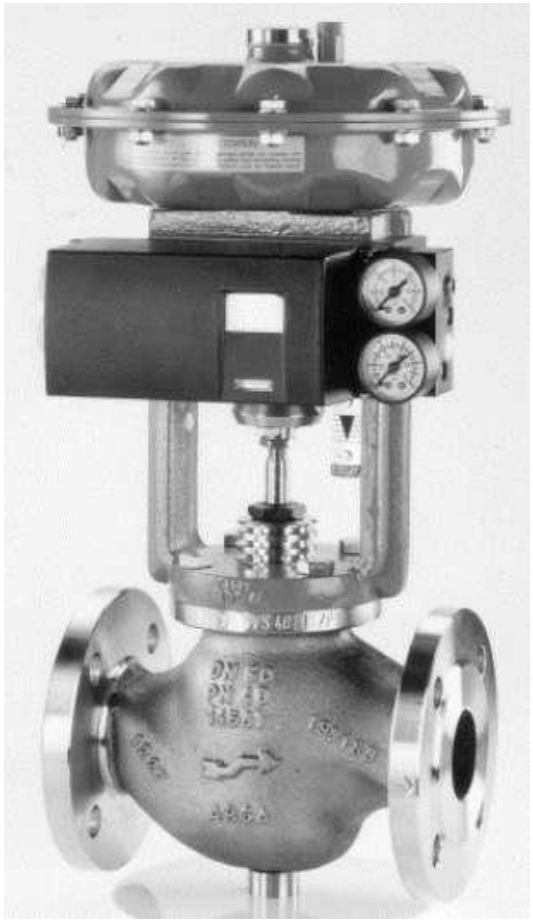


Figure 794. Valve position indicator

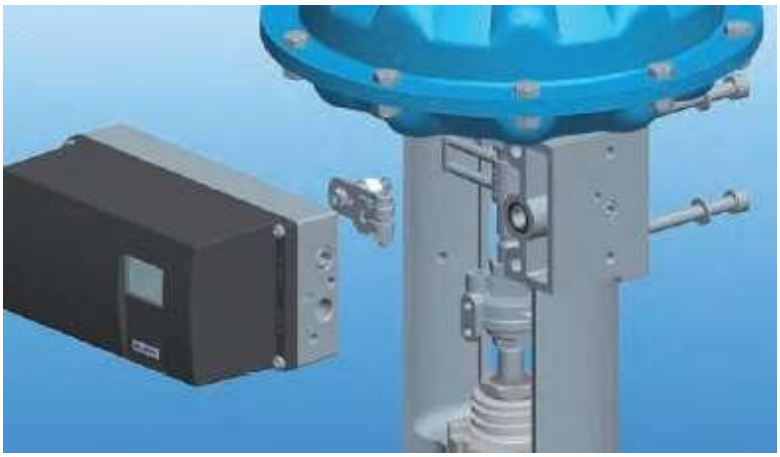


Figure 795. Valve position indicator mounting on the valve

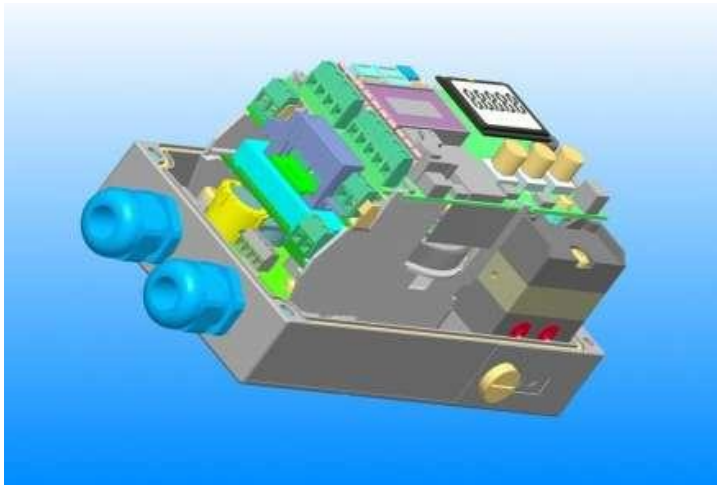


Figure 796. Electronics module of valve position indicator

7) - Radial Vibration

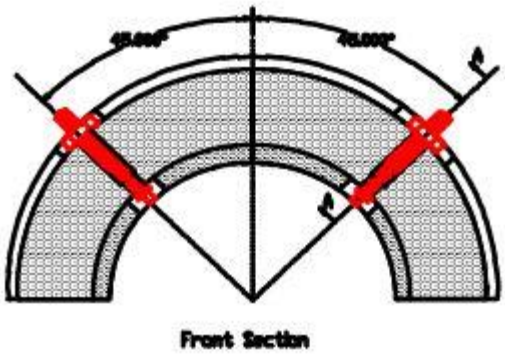



Figure 797. Radial vibration monitor

Radial vibration is usually the heart of the steam turbine monitoring system. It gets the most attention and generally gives the first indication of out of specification conditions. Most Original Equipment Manufacturer systems utilized a shaft rider transducer system to monitor vibration with a shaft absolute output signal. An exact replacement transducer system can be supplied, but most customers and OEMs are specifying a Eddy Probe Systems. A complete vibration system would install two sensor systems per bearing with the sensors located 90 degrees from each other.

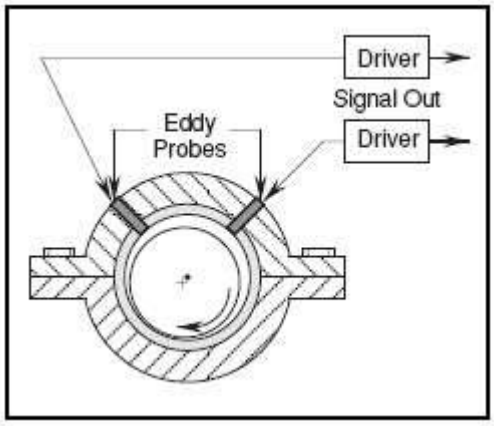
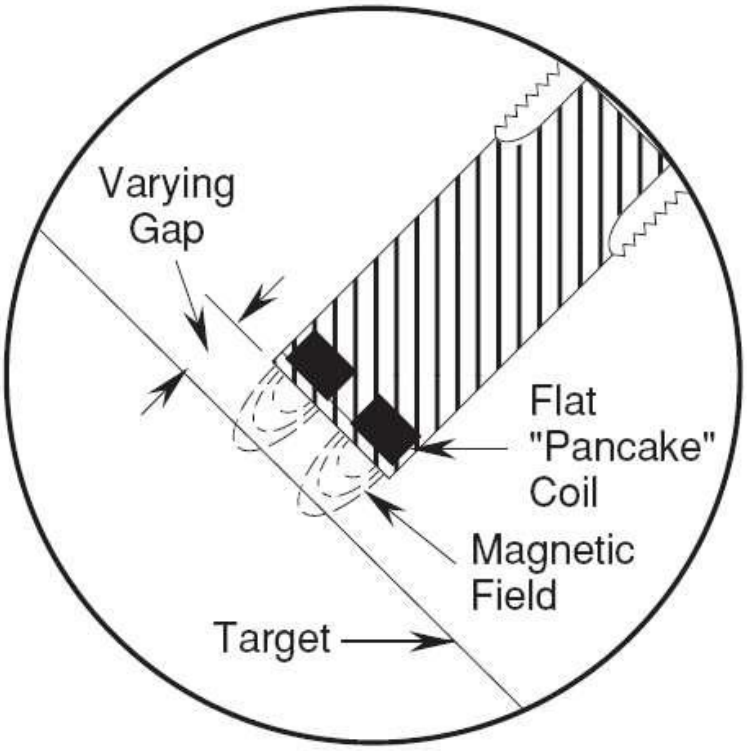



Figure 798. Eddy probes for radial vibration

The Eddy Probe is used to measure radial or axial shaft motion. It is mounted through or to the side of a bearing cap and observes the shaft's movement relative to its mounting position. An Eddy Probe System comprises a Probe, a Driver (oscillator demodulator), and an Extension Cable. Eddy Probe Systems have excellent frequency response. They have no lower frequency limit and are used to measure shaft axial position as well as vibration.

Figure 799. Eddy probes and connecting modules




***Eddy Probe Tip.***

Figure 800. Eddy probe magnetic fields determine distance from turbine shaft

8) - Speed and Acceleration

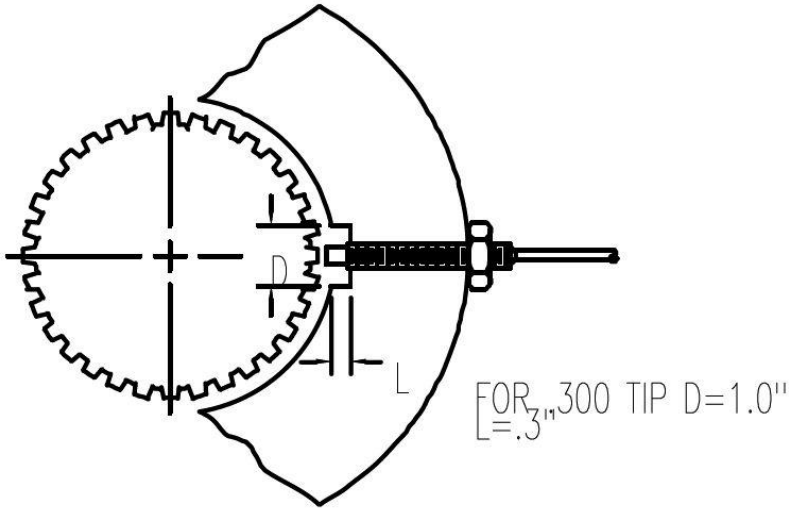



Figure 801. Speed sensor

Turbine speed indicators supplied by Original Equipment Manufacturers come in many forms: observing a gear wheel located inside the front standard, electrically converting the generator output frequency, or monitoring the turning gear. A retro-fitted system using Eddy Probe's can be specified to observe any multi-toothed gear wheel. Applications monitoring generator output frequency without an integral turning gear may require installation of a custom gear wheel.

Speed is a measurement of shaft rotation in revolutions per minute. During start-up, speed is a critical measurement as it allows the operator to: increase speed quickly through shaft critical frequencies; hold the speed stable during “heat soak” plateaus; and, for electric generators, to accurately match the synchronous frequency before connecting the generator to the power grid. Acceleration measures how fast speed is increasing or decreasing. It is monitored by the operator during turbine roll up, so that a steady increase in machine speed is achieved. Once the turbine is in normal operation, acceleration is not monitored.

9) - Temperature

Bearing temperature is a measure of the how hot a bearing is operating. It may be due to overloading, misalignment, improper lubricant pressure and/or flow.

Nearly all turbine generator bearings were originally installed or retro-fitted with bearing temperature sensors. These sensors may be thermocouples or RTDs. This parameter is often overlooked possibly due to the OEM output display located at some other panel not within the vicinity of the retro-fitted TSI system. Any bearings that were not originally equipped with temperature sensors can be retro-fitted to accept thermocouples or RTDs.

Figure 802. Temperature probe with wiring cap

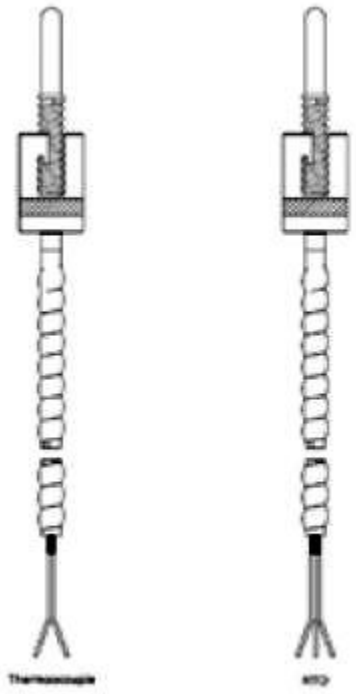


Figure 803. Temperature probes

## 6. What are synchroscopes?

Synchroscopes are used to synchronize an oncoming electrical generating turbine to the electrical grid. The speed changer is adjusted so that the speed of the turbine matches the 60 Hertz of the grid. As the needle is turning slowly in the fast direction, the main breaker is closed at 5 minutes to 12:00. This allows for the split second that it takes for the main breaker to close so that it should close at 12:00 when the needle is straight up. After the turbine is synchronized, the speed changer becomes a load changer as the turbine will not accelerate beyond 3600 rpm for a 2 pole AC generator in the United States. The load changer is increased immediately to start putting electricity onto the grid.

Figure 804. The synchroscope is at the bottom of these three gauges

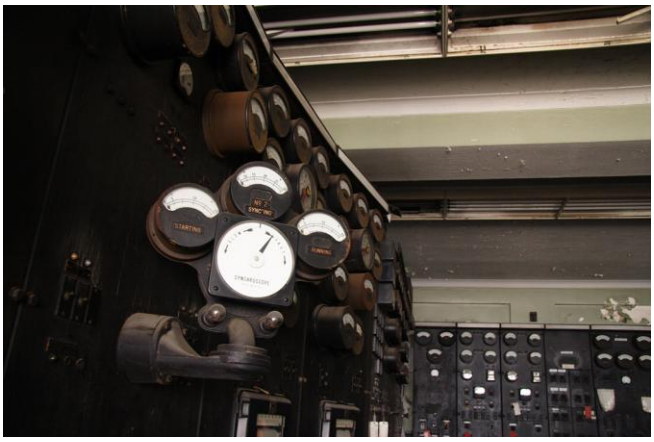


Figure 805. The synchroscope is the larger gauge at the bottom

Figure 806. Close-up of synchroscope. This is where the needle should be after synchronization

## 7. Explain the exhaust hood sprays

The exhaust hood cooling system generally consists of the following components:
· The low pressure turbine casing
- The exhaust hood sprays
· The exhaust hood spray valve and piping
· The exhaust hood temperature transmitter(s) and thermostats

The tips of turbine blades travel at high velocities. The velocity of the longer buckets, which are found in the low pressure turbine stages is greater than that of shorter buckets. The last stage buckets may have a tip velocity of as much as 1,200 miles per hour. Whenever an object travels through a gas (such as air or steam) at such high velocities, the object is heated by aerodynamic heating. The friction of gas molecules causes aerodynamic heating as they pass over an object similar to that caused by solid surfaces rubbing together. If buckets are heated too much, their temperature becomes so high that the metal strength is lowered and damage occurs.

Another factor unrelated to aerodynamic heating can aggravate the tendency for the low pressure turbine to be overheated at low loads, such as when the reheat temperatures are relatively high at low loads. This tends to increase the temperature of the steam in the low pressure turbine. Because the low pressure turbine last stage buckets are longest. They travel at the highest speeds, and they become hotter faster than the shorter buckets in the turbine. Although bucket temperature should be monitored, there is no satisfactory way to directly measure the temperature of buckets.

However, when the buckets become hot they heat the exhausting steam and the exhaust hood.
This heating is the major reason that exhaust hood temperature is monitored. When exhaust hood temperature rises above acceptable limits, it is a good indication that the buckets are too hot, the blades of the low pressure turbine are cooled when necessary by spraying cool water through nozzles which resemble shower heads, near the last stage blades. There are usually four to six nozzles mounted on the low pressure inner casing. The temperature of the exhaust hood is usually monitored by thermocouples for indication in the control room. There are usually thermostats that provide an alarm (usually set about 175 °F) if the exhaust hood temperature exceeds recommended limits and a turbine trip at a set point above that (usually about 225 °F). Pneumatic temperature transmitters provide an air pressure signal proportional to exhaust hood temperature to a pneumatic controller that positions a spray valve that in turn controls the flow of water to the spray nozzles.

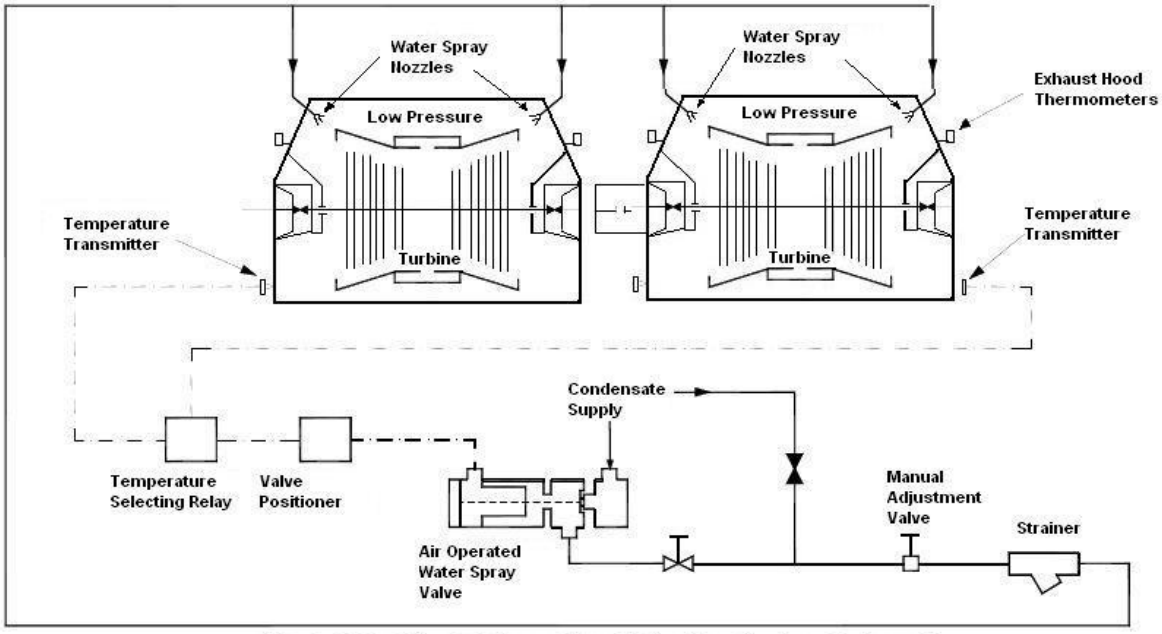



Figure 807. ***Typical Turbine Exhaust Hood Cooling System Schematic***

# Chapter 26 Turbine Starting and Stopping Procedure

**Start a condensing turbine - Skrotzki and Vopat Procedure:**

1. Check oil level

2. Start auxiliary oil pump and check oil pressure to bearings (10-15 PSI).

3. Open all cylinder casing drains. (also known as casing drains)

4. Open gland leak off valve.

5. Drain condensate from main steam header and steam leads.

6. Establish circulating water flow through condenser.

7. Start condensate pump.

8. Establish seal on high pressure gland for starting condition.

9. Establish seal on low pressure gland for starting condition.

10. Close vacuum breaker (atmospheric valve) and establish water seal on vacuum breaker.

11. Start condenser air ejector.

12. Close cylinder drains to stages under vacuum.

13. Turn on water generator air or hydrogen cooler.

14. With partial vacuum established 24" to 26" hg. quickly admit enough steam to start rotor spinning the shut off.

15. Listen for rubs on the casing and at seal locations.

16. If no rubs are evident admit enough steam to establish a rotor speed of about 200 R.P.M. Maintain about 1/2 hr to warm up casing and rotor evenly.

17. Open cylinder casing drains to stages not under vacuum.

18. Trip emergency hand control to make sure turbine shuts off.

19. Close throttle, reset trip, reestablish steam flow and slowly increase speed towards rater R.P.M. during the next 15 minutes. If rotor vibrates severely, decrease speed and continue warm-up until no objectionable speed occurs on speed increase.

20. Adjust high and low pressure seals for operation (shut of sealing steam going to high pressure end. Leave on at low pressure end.)

21. Turn on water gland sealing water. (High Pressure end)

22. Close the cylinder casing drains that are not in a vacuum.

23. Turn on water to oil cooler to maintain an outlet oil temperature of 110 degrees Fahrenheit.

24. Continue to open throttle valve until the turbine reaches rated speed and the governor takes over.

25. Make sure the governor takes over by watching the tachometer. If it does not show a speed increase upon continued opening of the throttle valve wider then the governor has taken over. Also you will see the bar lift mechanism on the turbine start closing.

26. Trip the governor by overspeeding to make sure overspeed trip is working.

27. Shut off steam throttle valve, reset the overspeed trip, reopen the throttle valve and bring unit up to speed.

28. Close off the oil line supplying oil to the low oil pressure trip to trip turbine on low oil pressure.

29. Reopen oil line, again we shut off the steam throttle, reset the overspeed trip and reopen the steam throttle.

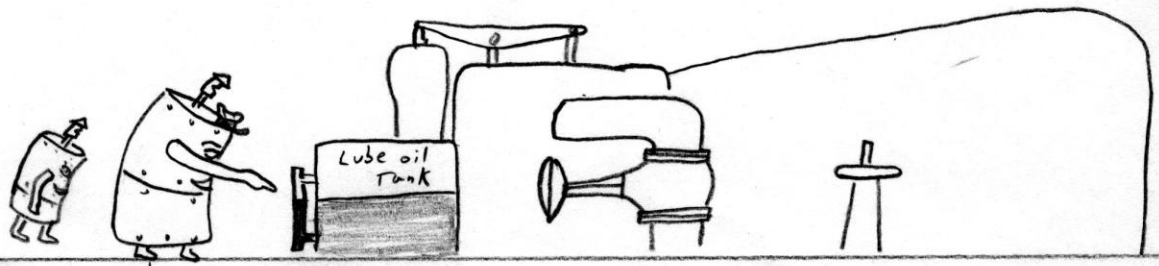
30. Synchronize by closing the electrical breaker onto the grid when the synchroscope is at 12:00 or at 5 minutes to 12:00 when the synchroscope is traveling slowly in the fast or clockwise direction. This to allow for the split second it takes for the large breaker contacts to actually close. Then by turning the speed adjuster knob we increase load on the turbine. The turbine is now locked on the grid and any increase in steam supplied to the turbine increases the K.W. output.

31. Open bleed line valves and put heaters into operation.

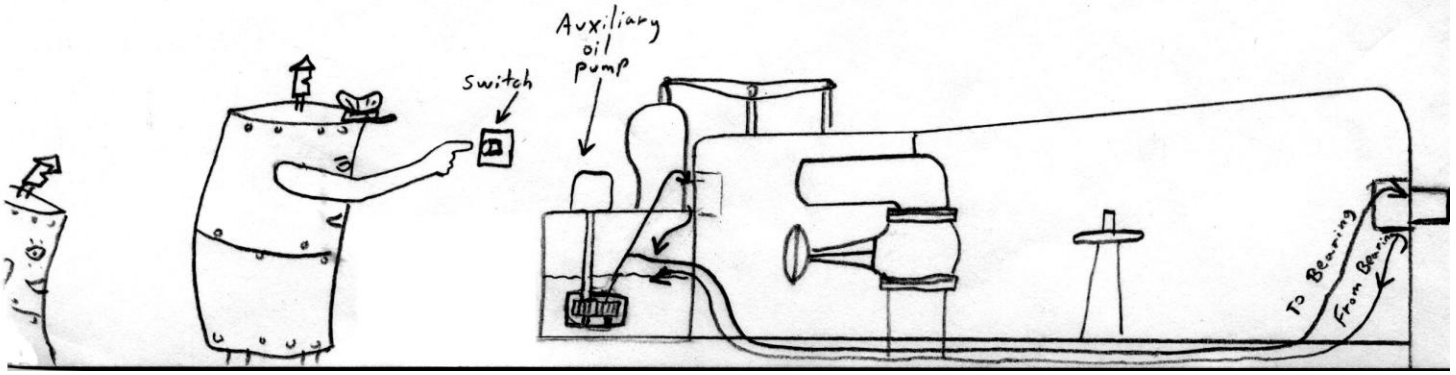
32. Bring unit up to share full load.

# The Adventures of Boiler Bill and Toot Sweet

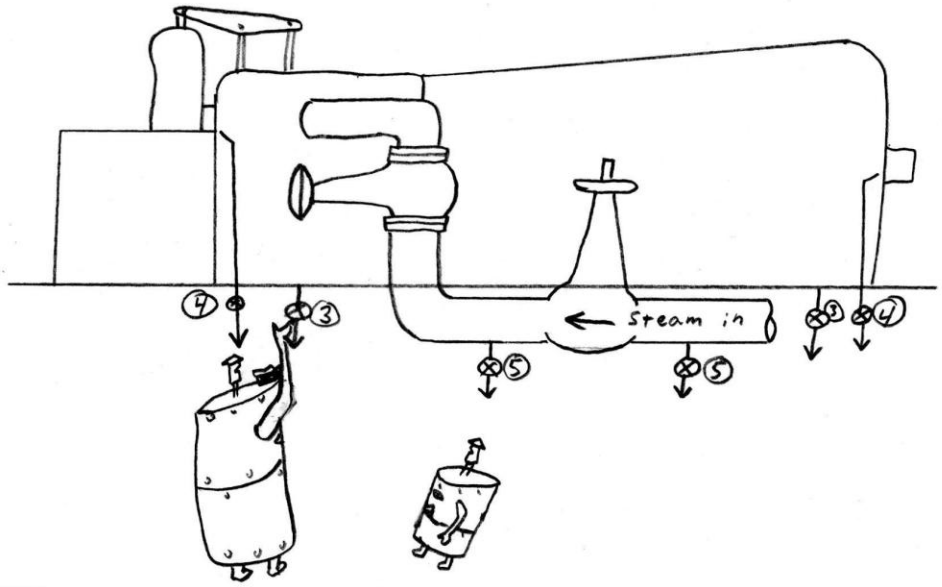
① Check oil level in reservoir



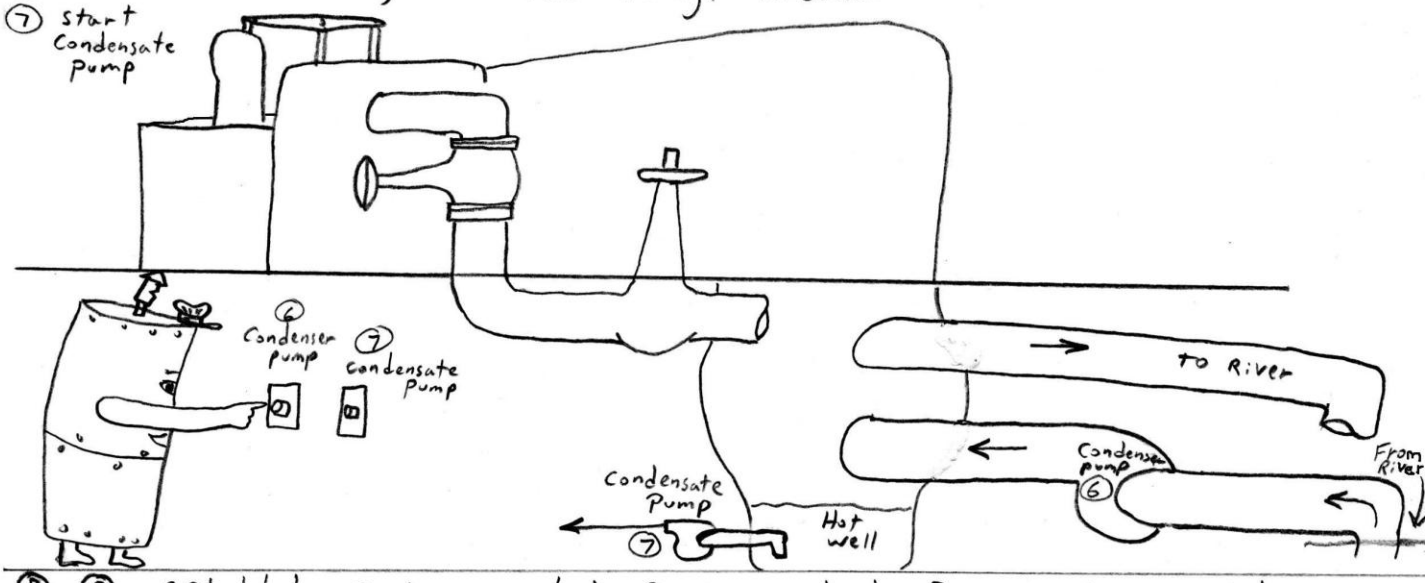

② Start auxiliary oil pump and check oil pressure, 10-15 psi to main bearings



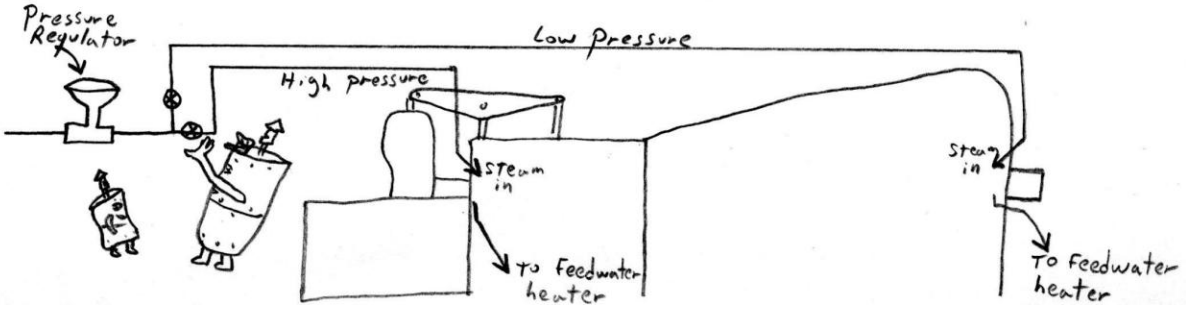
(3.) open all cylinder casing drains
(4.) open Gland Leak off valves
(5.) Drain condensate From the main steam header and steam leads



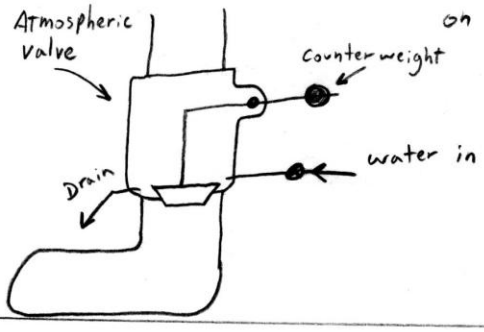

(6) establish circulating water Flow through condenser
(7) start Condensate Pump

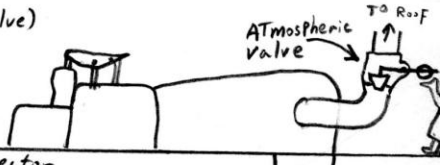



(8) (9) establish seal on high pressure gland For starting condition
establish seal on low pressure gland For starting condition

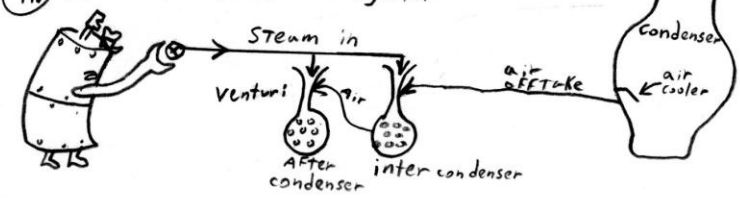


(10.) close vacuum breaker (atmospheric valve) and establish water seal on vacuum breaker



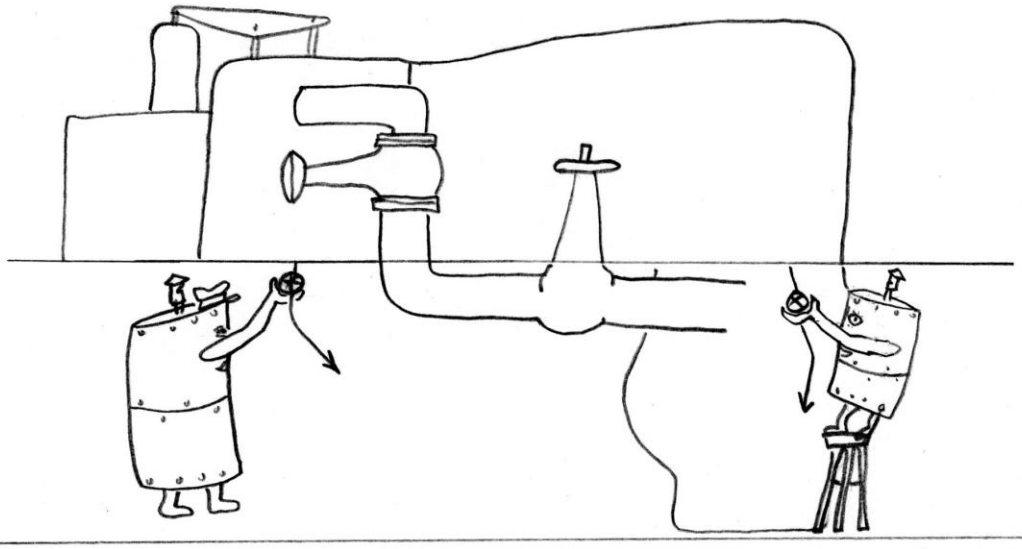




(11.) Start condenser air ejector



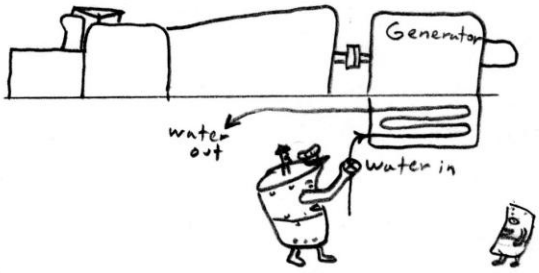

(12)

Close cylinder drains to stages under vacuum

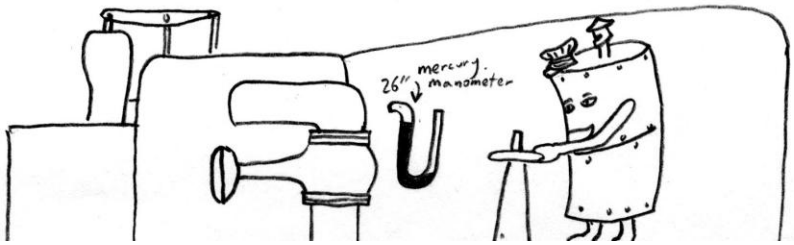


(13)

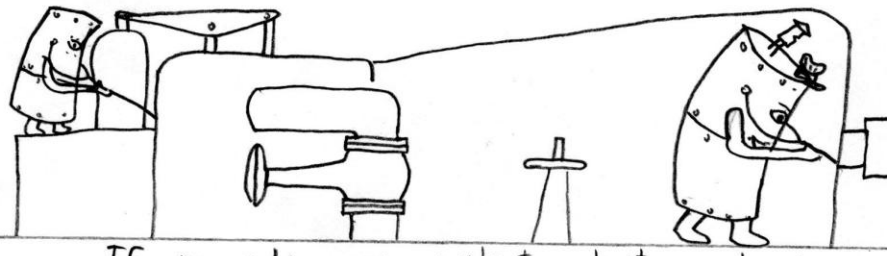
turn on water to generator air or hydrogen cooler



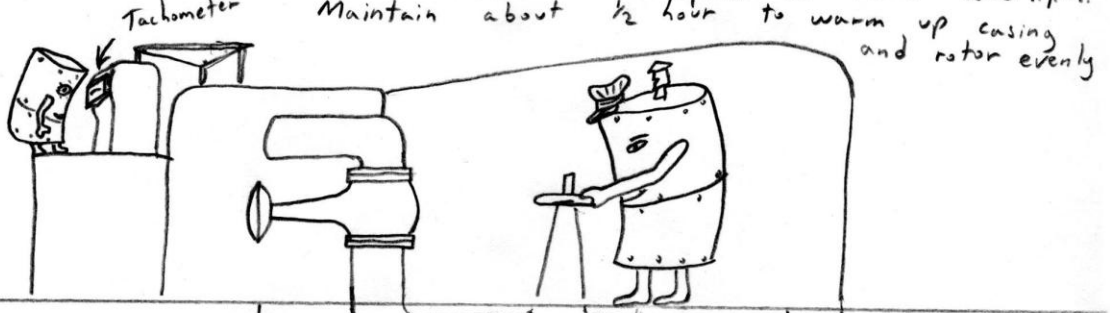

(14) with partial vacuum established, 24 to 26" mercury, quickly admit enough steam to start rotor spinning then shut off



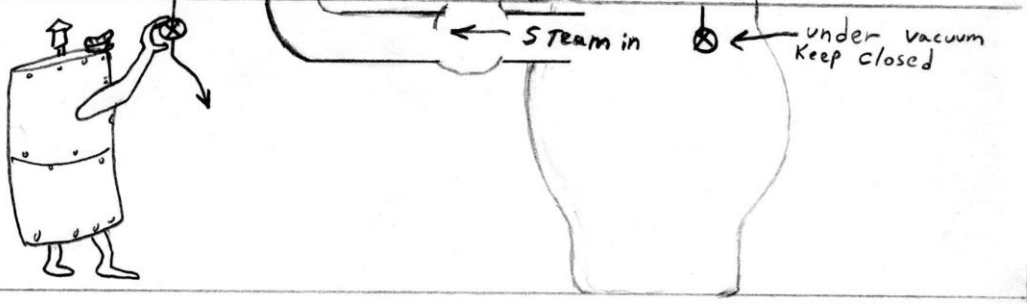
(15) Listen For rubs on casing and at Seal locations



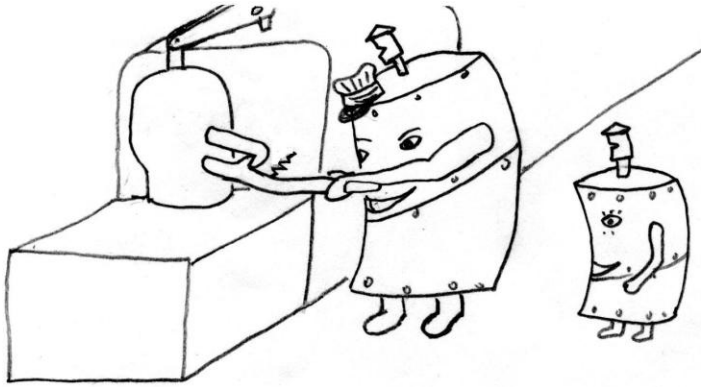
(16) IF no rubs are evident, admit enough steam to establish a rotor speed of about 200 rpm. Maintain about ½ hour to warm up casing and rotor evenly




(17) open Cylinder casing drains to stages not under a vacuum

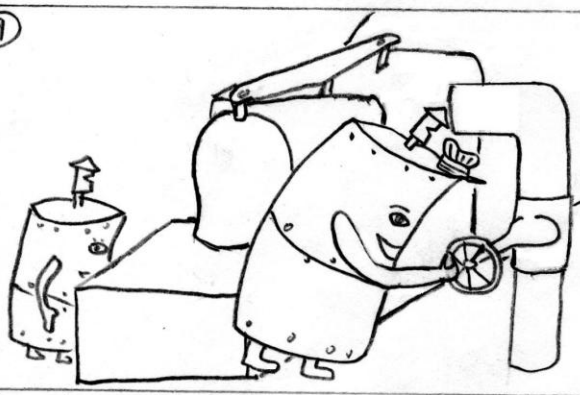


(18)



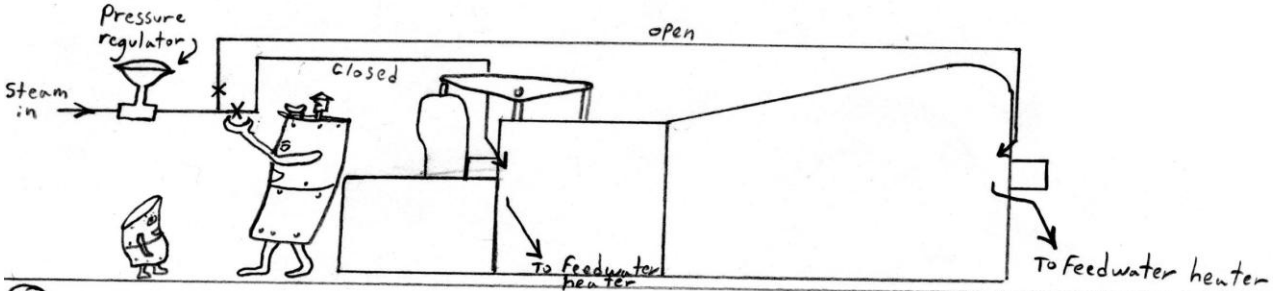
Trip emergency hand control to make sure turbine shuts off

(19)



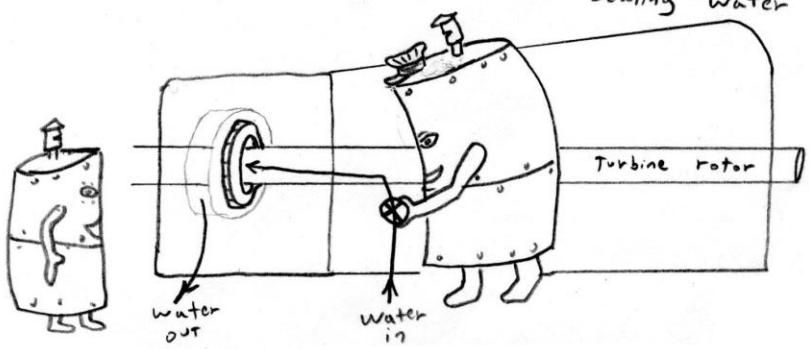
Close throttle. Reset trip. Re-establish steam flow and slowly increase speed toward rated RPM during the next 15 minutes. If rotor vibrates severely, decrease speed and continue warming up until no objectionable vibration occurs on speed increase

(20) adjust high and low pressure seals for operating. Shut off sealing steam going to high pressure end.

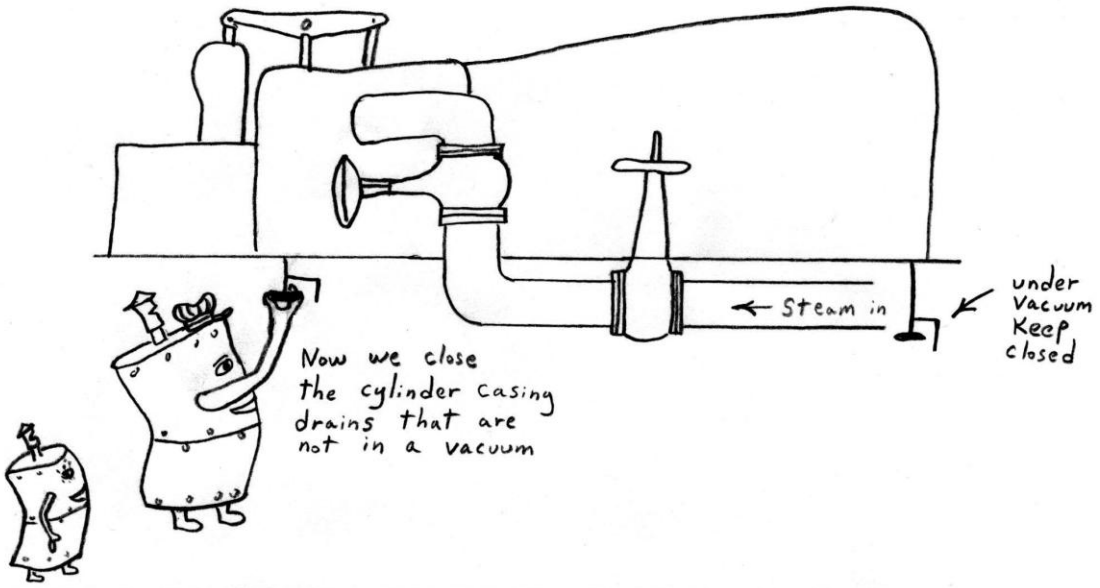



(21)

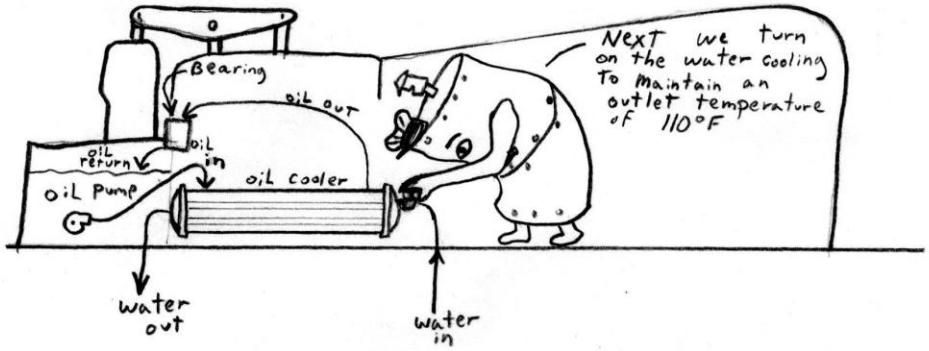
Turn on water gland sealing water



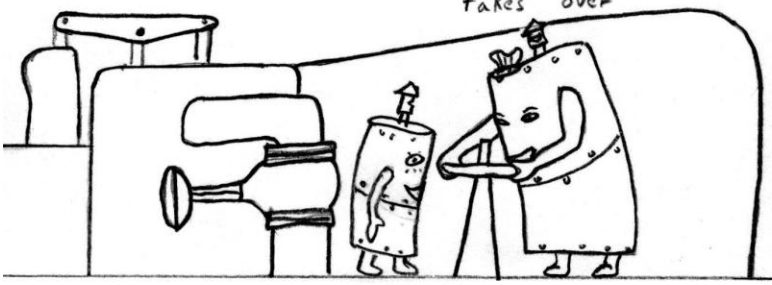
22

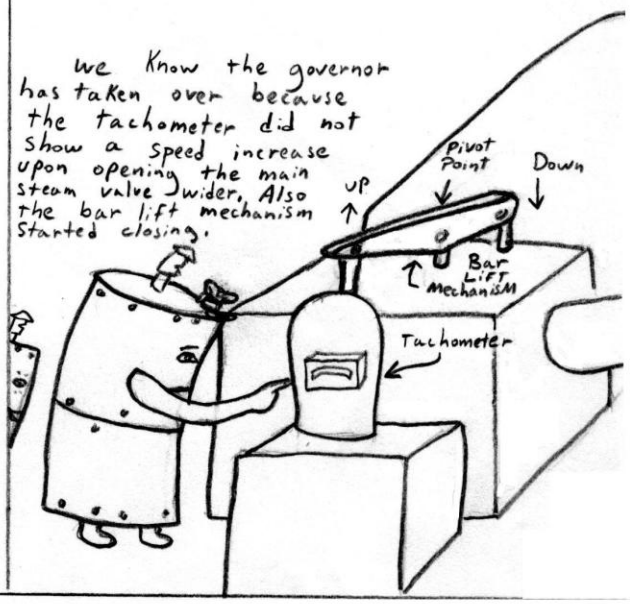

Steam in
under Vacuum Keep closed
Now we close the cylinder casing drains that are not in a vacuum

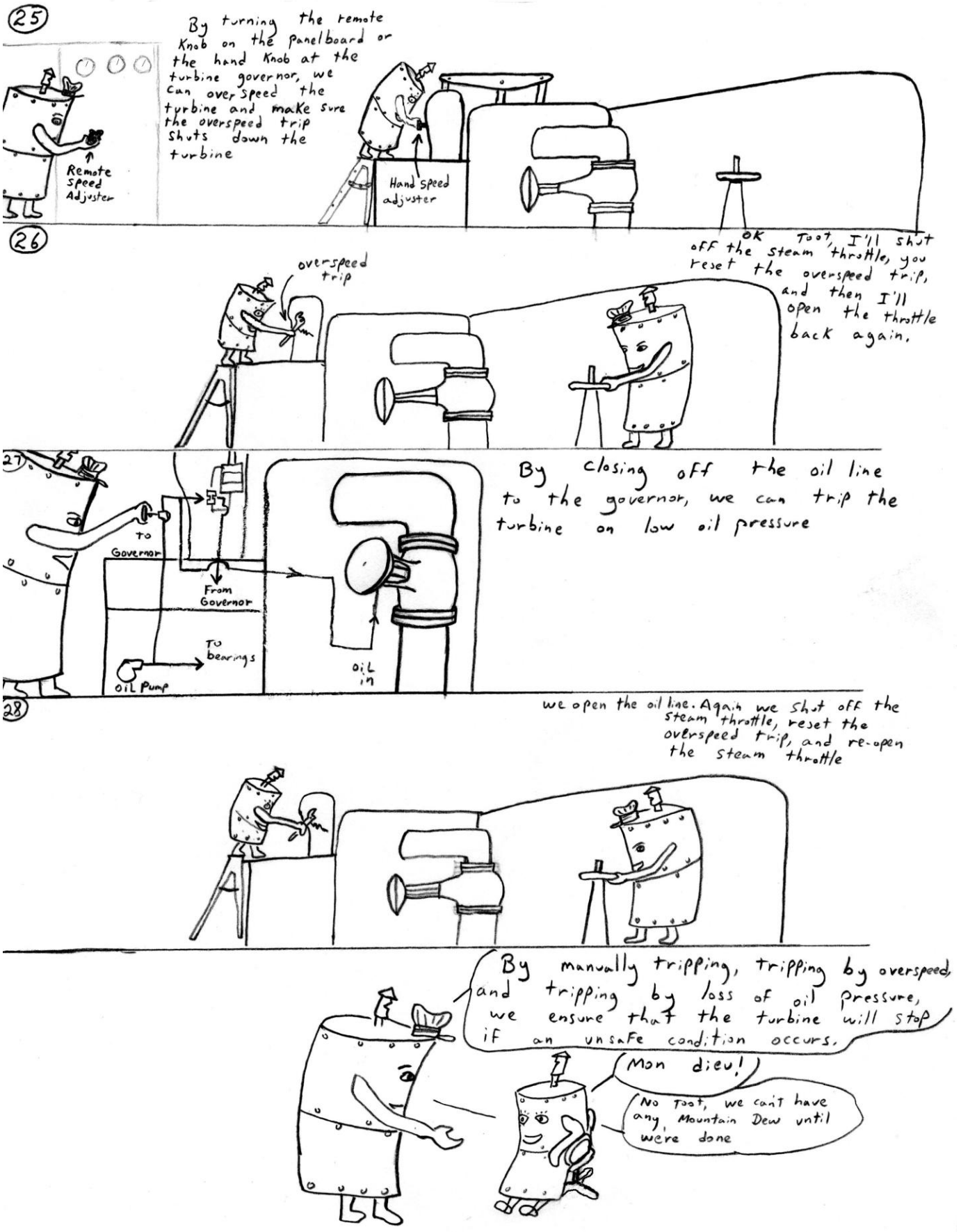
23

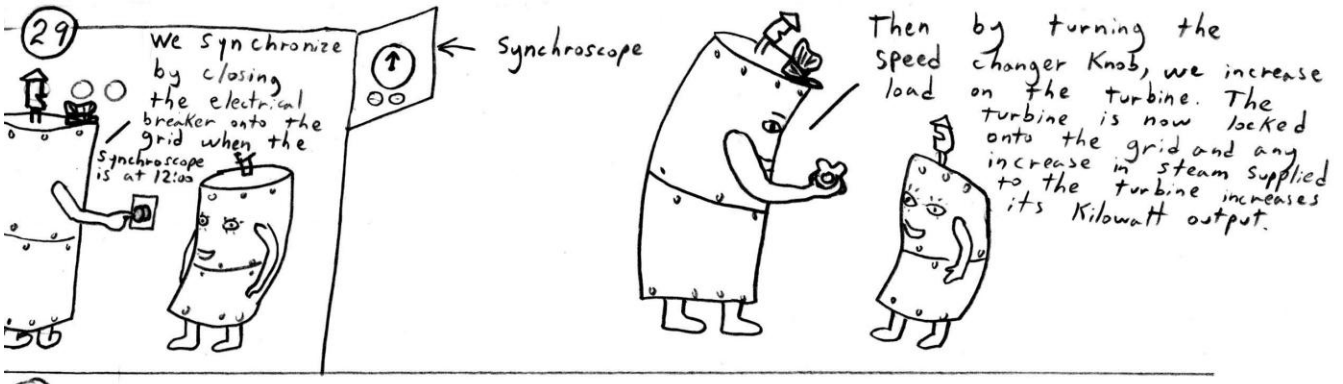

Bearing
oil out
oil return
oil in
oil Pump
oil cooler
Next we turn on the water cooling to maintain an outlet temperature of 110°F
water out
water in

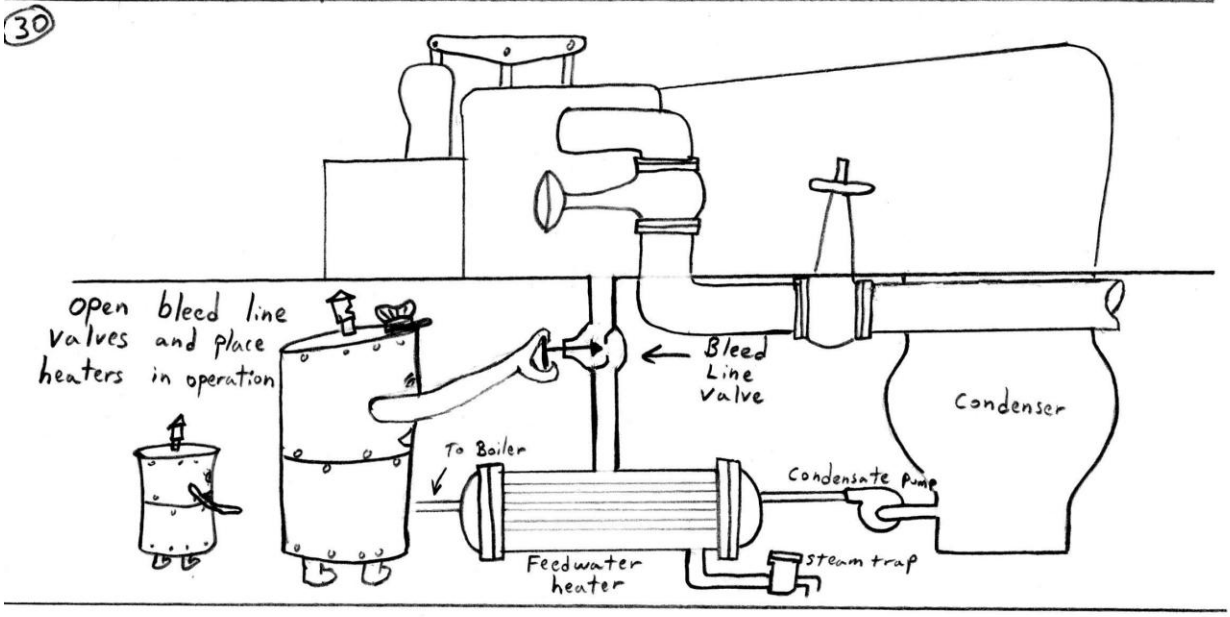
24

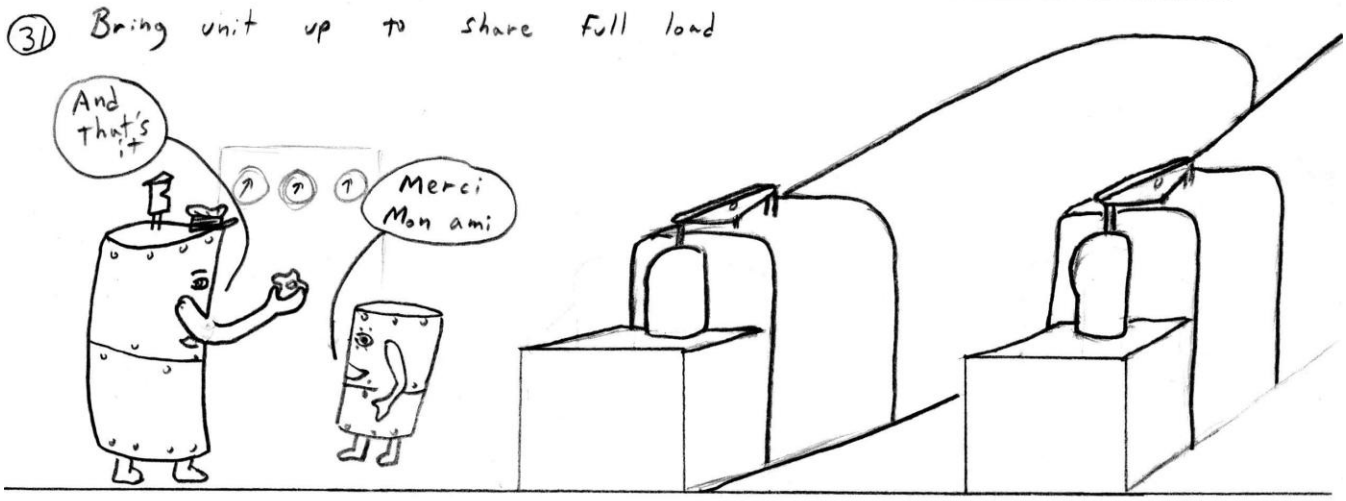

we continue to open the throttle valve until the turbine reaches its rated speed and the governor takes over


we know the governor has taken over because the tachometer did not show a speed increase upon opening the main steam valve wider. Also the bar lift mechanism started closing.
Pivot Point
Down
up
Bar Lift Mechanism
Tachometer


25
By turning the remote Knob on the panelboard or the hand Knob at the turbine governor, we can overspeed the tyrbine and make sure the overspeed trip shuts down the turbine
Remote Speed Adjuster
Hand speed adjuster
26
OK Toot, I'll shut off the steam throttle, you reset the overspeed trip, and then I'll open the throttle back again.
overspeed trip
27
By closing off the oil line to the governor, we can trip the turbine on low oil pressure
To Governor
From Governor
To bearings
oil Pump
oil in
28
we open the oil line. Again we shut off the steam throttle, reset the overspeed trip, and re-open the steam throttle
By manually tripping, tripping by overspeed, and tripping by loss of oil pressure, we ensure that the turbine will stop if an unsafe condition occurs.
Mon dieu!
No Toot, we can't have any Mountain Dew until we're done


29
We synchronize by closing the electrical breaker onto the grid when the synchroscope is at 12:00
Synchroscope
Then by turning the speed changer Knob, we increase load on the turbine. The turbine is now locked onto the grid and any increase in steam supplied to the turbine increases its Kilowatt output.


30
open bleed line valves and place heaters in operation
Bleed Line Valve
Condenser
To Boiler
Condensate Pump
Feedwater heater
steam trap


31 Bring unit up to share full load
And that's it
Merci Mon ami

# Chapter 27 Normal Operation

## 1. What does the term "ramp rate" mean?

Ramp rate is the time that must be taken to warm up a turbine evenly. The ramp rate is the rate of metal temperature increase per hour as the turbine is being brought up to normal operating temperature. The ramp rate for heating up a turbine casing is 100° F. per hour if the Manufacturers specifications are not known. Turbines should never be operated below 20% of rated load to prevent overheating of low pressure exhaust casing.

Ramp rate is used in bringing a turbine up to operating temperature and is the degrees Fahrenheit rise per hour that metal surfaces are exposed to when bringing a machine to rated conditions. Manufactures specify ramp rates for their machines in order to avoid thermal stresses. Thermocouples are used in measuring metal temperatures.

## 2. What is a boilers ramp rate?

A boilers ramp rate is 300° per hour.

*Joe Grubb*

## 3. How are the differences in ramp rate handled in a unit system where there is one boiler hooked to a dedicated turbo-generator?

The turbine will have certain “soak” periods where it will run at a set speed to allow it to expand evenly and the boiler and turbine can warm up together.

## 4. Why must steam turbines be warmed up gradually?

Although it is probable that a turbine can, if its shaft is straight, be started from a cold condition without warming up, such operation does not contribute to continued successful operation of the unit. The temperature strains set up in the casings and rotors by such rapid heating have a harmful effect. The turbine, in larger units especially, should be warmed slowly by recommended warm-up ramp rates because of close clearances.

## 5. What is steam rate or water rate as applied to turbo-generators?

The steam rate is the pounds of steam that must be supplied per kilowatt-hour of generator output at the steam turbine inlet. Water rate is the same as the steam rate. If a turbine uses 100,000 pounds of steam an hour, it needs 100,000 pounds of water an hour to supply it.

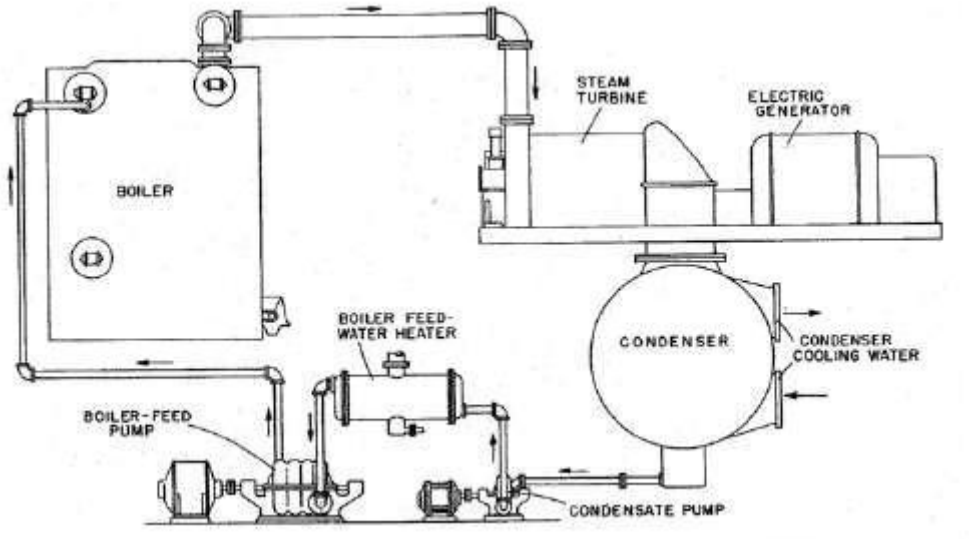



Figure 808. If 100% of all condensate is pumped back to the boiler, the weight of the steam supplied will equal the weight of the condensate returned.

## 6. What is meant by "heat rate" of a turbine?

The "heat rate" is the amount of energy input to the turbine for each unit of energy output.

"Heat rate" is the number of BTU's which must be supplied by the boiler to the steam for each KWH or H.P. hr generated.

*Stationary Engineering, Steingress & Frost*

## 7. Is the vacuum on the turbine to be increased before or after the gland sealing steam is started?

The steam seal on the high and low pressure ends are started just before the vacuum is applied through the use of the hogging jet and then the steam operated air ejector, if the vacuum were applied first, air would be pulled in and have to be removed by the ejector. For this reason the seal is first established.

*S&V page 129*

## 8. What is left running when a turbine is shut down?

The auxiliary oil pump. During the shut down procedure you should keep a close eye on lubrication. Make sure that the auxiliary oil pump starts and that this pump is left on until the unit cools down. If a turning gear is used, lubrication must be provided by the turning gear pump and this should be checked also.

*S&V page 129*

## 9. List 11 steps of good operating practice.

Steps for good operating practice are:

1. Because of close clearances, avoid operations that cause unequal expansions.

2. Avoid passing steam through a turbine with the rotor at rest.

3. Avoid drawing air through the glands with the rotor at rest.

4. Avoid unnecessary heating of the low pressure end of a turbine by running it for prolonged periods below 20% of rated capacity.

5. Always check the stop valve tripping mechanism during startups and shut downs. Be sure stop valve is shut off before resetting.

6. Check the governor and automatic control operation at every opportunity.

7. During normal operation, occasionally check operation of the auxiliary oil pump.

8. Be sure cylinder and steam mains are drained free of condensate before admitting steam to the turbine.

9. Periodically check oil in system for contamination.

10. Immediately repair leaks in any part of oil system.

11. Log hourly readings of steam, oil pressures, and oil temperatures.

# Chapter 28 Efficiency Testing, Inspection and Upgrading

## 1. What are the losses in a turbine?

Turbine loses are

1) The inability to fully develop the mechanical energy from the available heat.

2) Energy

3) Throttling

4) Steam leakage

5) Bearing losses

## 2. Name some reasons for a loss of efficiency in a turbine.

1) Frictional losses at the surfaces over which the steam rubs.

2) Eddy losses, which are introduced whenever the current of the steam suffers an abrupt change in direction, as when the steam current strikes anything but the desired surface.

3) Windage loss; these are occasioned by the motion of the turbine parts within a space that is filled with steam vapor.

4) Radiation losses; i.e., the heat that is lost as such from hot surfaces.

5) Exhaust losses, due to the velocity that is not converted into work.

6) Leakage losses introduced when steam flows through the turbine, or part of it, without passing through the desired path.

*Croft Steam Turbine Principles and Practice 2nd Edition. 1940. page 17*

## 3. How much pressure is put on a casing during a hydrostatic test?

During a hydrostatic test 1.5 times normal steam pressure is used.

*S&V page 65*

## 4. What will an increase in steam pressure do to turbine efficiency?

In general it can be said that increasing steam pressures and temperatures improve performance, with the exception of a small range of pressures near the critical.

*S&V page 190*

## 5. In modern plants, what is the moisture limit in steam heading to a turbine?

In present day plants elaborate methods of washing and separation are used to eliminate water droplets leaving the boiler. These methods reduce the water content of the steam by 99.9 percent, but the remaining 0.1 percent will carry over enough chemicals to form undesirable deposits in the turbine over a period of time. Measures must be taken to clean the turbine periodically.

*S&V page 125*

## 6. At what % of full load do turbines run most efficiently?

Turbines for the generation of stationary power will be designed to operate most of the time at the optimum speed ratio. Since very few prime movers for this class of service always operate at full load, it will be usually anywhere from about one - half to three fourths of rated capacity, depending on the nature of the load curve.

*S&V page 167*

## 7. What is a "condition line"?

A "condition line" is a line plotted on a Mollier chart which expresses a turbine's performance.

## 8. An acceptance test for a new turbine should be done within what time period.

The ASME test code for steam turbines states that an acceptance test should be made within two (2) months of the time the turbine is first placed into commercial service. The test should be run under specified conditions of load, temperatures and pressures. The length of the test should allow time to check several readings to insure consistent and accurate results.

*D.E.S.C. Turbines. page 32.*

## 9. How would an engineer estimate a new turbine's performance? Why is this done?

Estimating new turbine performance is done to give an engineer some idea of what turbines at different steam conditions can be expected to do. It is based fundamentally on curves.

## 10. How do you check turbine performance? What is "average heat rate"? What are performance corrections done for?

Checking turbine performance requires collecting and logging sufficient data during operation periods to enable one to figure performance.

Average heat rate = total steam (hl - hf) + total KwHr.

The work done by steam, the heat rate, the thermal efficiency, and the steam rate all vary with initial steam pressure and temperature. The reason for using high steam pressure and temperature is principally to improve efficiency of operation that can be realized in terms of lower fuel consumption.

## 11. What does the Willans line show?

The Willans line is a plot of throttle flow versus the load, usually expressed in kilowatts; generally it is a straight line except for low and high loads. The Willans line is used to show steam rates at different loads on the turbine.

## 12. What is the Willans line in reference to the operation of a turbine?

One way of expressing steam-turbine performance is by the means of an input-output curve. The input is steam consumption expressed as steam flow in pounds of steam per hour, and the output as load either in horsepower or kilowatts. The plot of total steam consumption verses load is known as a Willans Line, the peculiar characteristic of which is that it is straight. The plotted line shows that somewhere between 10 % to 20% of full load steam flow is needed to operate the turbine at zero load, because of various losses.

*D.E.S.C. Turbine Operation and Maintenance. page 33*

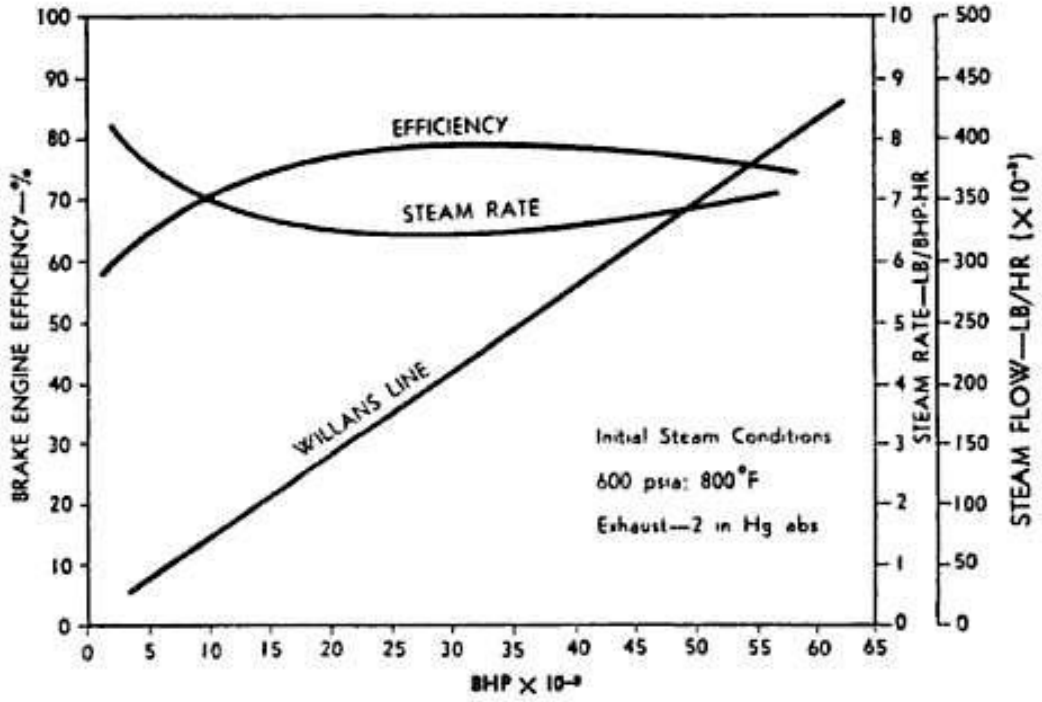



Figure 809. Willans Line chart

# Inspection and Upgrading

### 13. Explain fully the procedure for inspecting a turbine?

1. Check clearances.

2. Inspect blades.

3. Inspect dummy piston and seals.

4. Check cylinder bore.

5. Check governor.

6. Check throttle valve.

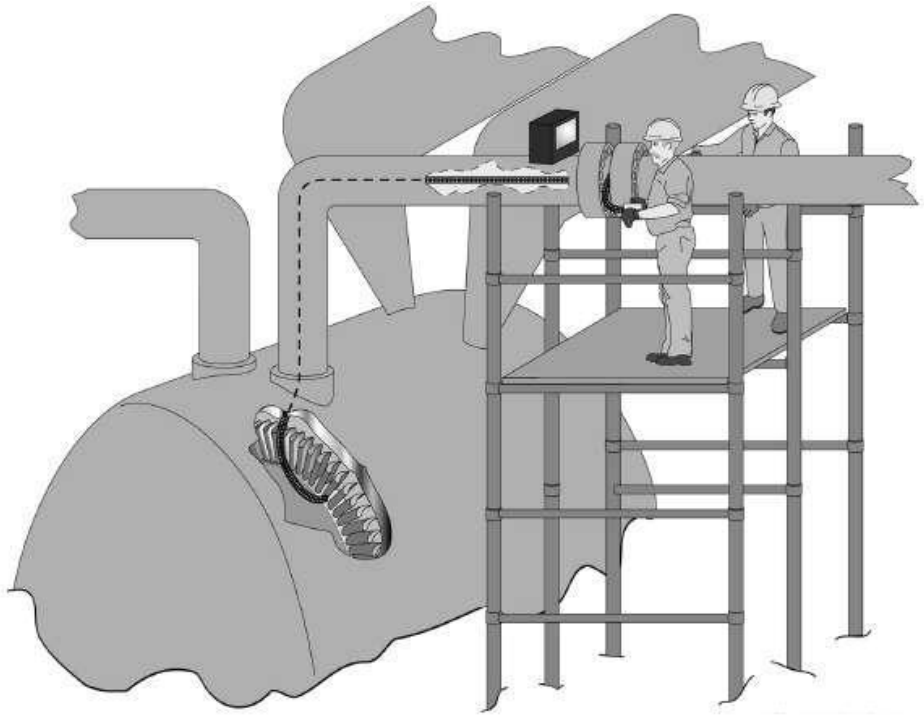
7. Check control valve.

8. Check bearings.

9. Check thrust bearings.

10. Check couplings.

11. Check auxiliaries.



Videoprobe Delivery Device for a Steam Turbine Inspection Application

Figure 810.

Figure 811. Inserting the Videoprobe

Figure 812. Videoprobe inside turbine

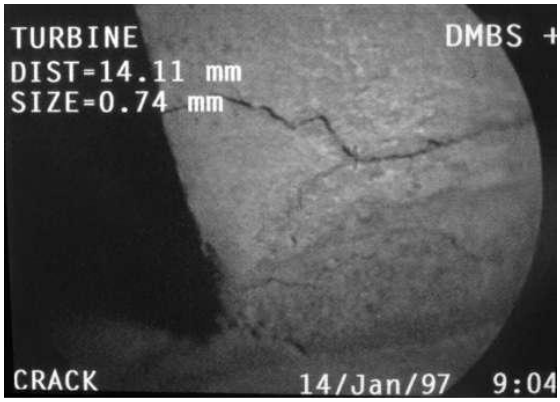



Figure 813. Crack discovered by the Videoprobe

## 14. When inspecting a turbine, what would you check before shutting down? The shroud ring clearance, the axial clearance, or oil pump pressure.

Axial clearance refers to lengthwise clearance between the rotating and stationary parts of a turbine. This can be adjusted while the turbine is in motion.

Shroud ring clearance is radial clearance between the casing and the ring around the blades. This clearance is changed only through wear in the bearing surface.

Clearance is important but both radial and axial clearance should be checked during start-up and warm-up. On shutdown the main concern is making sure the auxiliary oil pump comes on as the turbine driven pump slows down.

*Higgins Steam Turbines page 122*

## 15. What does "upgrading" generally means in the context of steam turbines?

Upgrading is a most widely used tern. It encompasses a variety of meanings verses life extension, modernization and up-rating of steam turbines.

## 16. When does upgrading mean modernization of utility industry?

Upgrading is really modernization to all those units other than those facing uncertain load growth and low-capital utility system. It involves replacement of damaged parts/components by state-of-the-art components without scrapping the entire machine.

## 17. In which case does upgrading imply life extension of steam turbines?

For a capital-short electric utility plant, upgrading comes to mean extending the life of that plant scheduled for retirement.

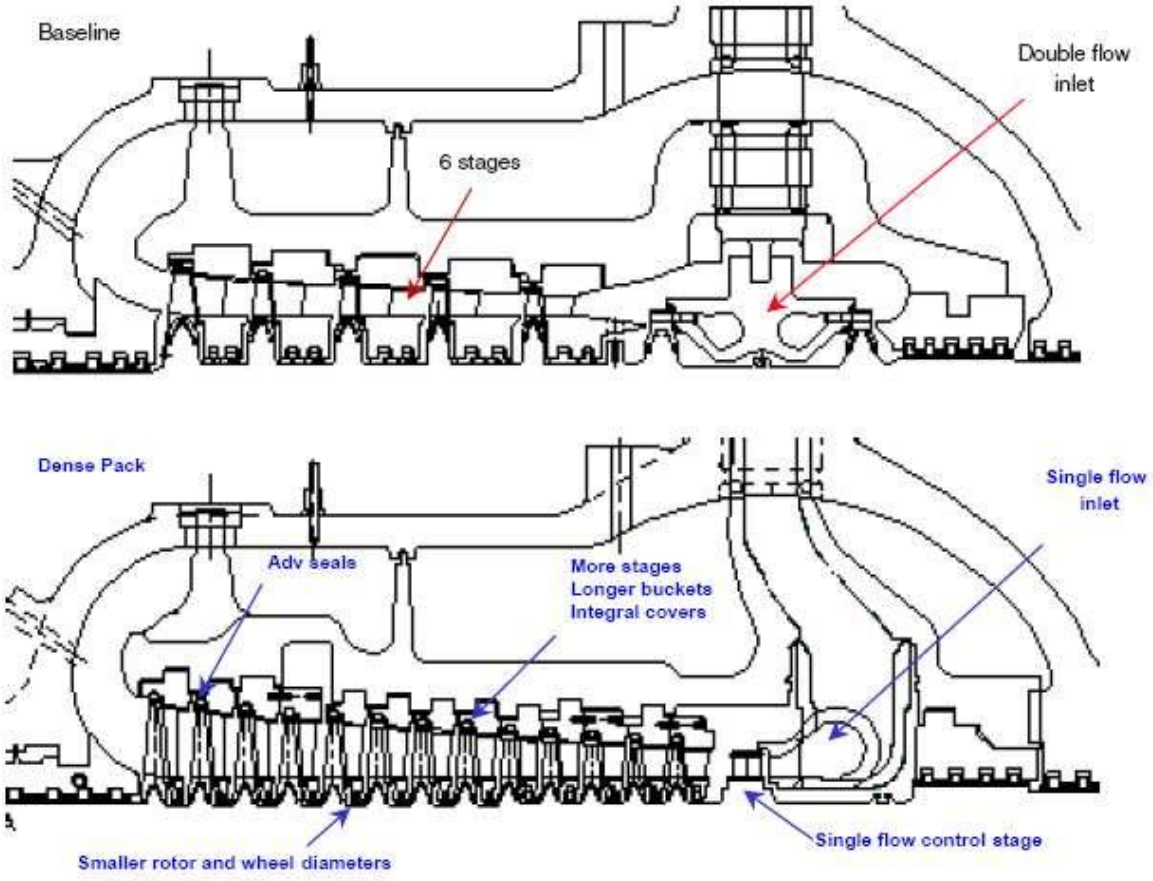
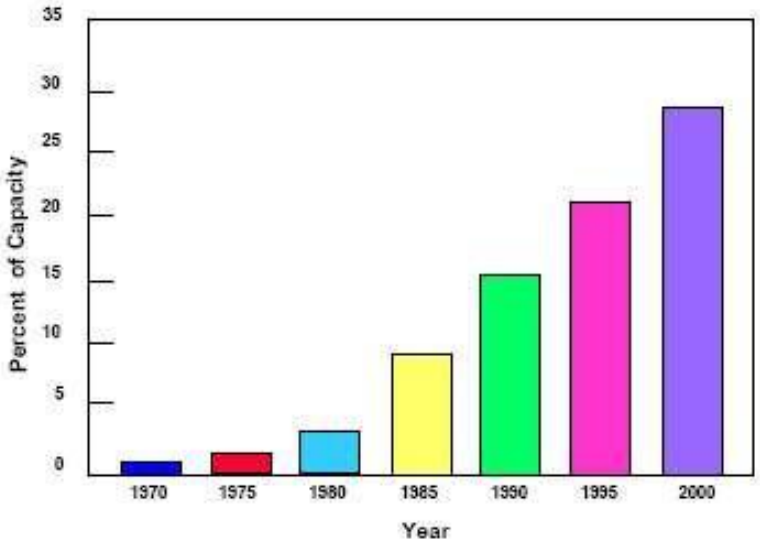



Figure 814. Before upgrade on top and after upgrade below showing differences in upgrade components for better efficiency

## 18. In which cases does upgrading mean up-rating the turbine capacity?

For an electric utility system facing uncertain load growth, upgrading is chiefly up-rating. It is an inexpensive way to add capacity in small increments.




Utility dependence upon units greater than 30 years old

Figure 815. Utilities are trying to make their turbines last as long as possible by upgrading rather than replacing.

Major electrical utilities evaluated their aging steam turbines and concluded it was more economical to extend the life of the equipment than to retire and replace the unit. This resulted in turbine life extension evaluations to identify equipment that needed repair or replacement in order to operate beyond the generally-accepted design life of 40 years. Talk of deregulation of the power industry during the mid-1990s created considerable uncertainty among the utilities. Decisions regarding the sale of generating and/or transmission and distribution assets were analyzed. One clear conclusion from the deregulation discussions was that the utilities were going to be in an extremely competitive environment in the future. The initial reaction to deregulation within the utility industry was to take a "wait and see" position. As decisions regarding the retention or selling of powerplants were made, demand for replacement power during peak periods soared and it became clear that additional capacity and improved efficiency would be needed in the future. The low cost producer of electricity with additional capacity would be the victor in the new, unregulated market. Today, in addition to addressing the aging of steam turbines, utilities are looking for the competitive edge that additional capacity and better performance will provide. Other factors that enter into the economic model are the desire for sustained performance with minimal degradation over period of at least ten years and the desire to extend time between major overhauls to at least ten years.

## 19.Which factors affect the extent of an upgrading program?

Age of the unit.

How it has been operated.

Note: Turbines less than quarter of a century old can simply be upgraded to their original design conditions.

Figure 816. Old turbine rotor and wheels on the left and new upgraded rotor and wheels on the right

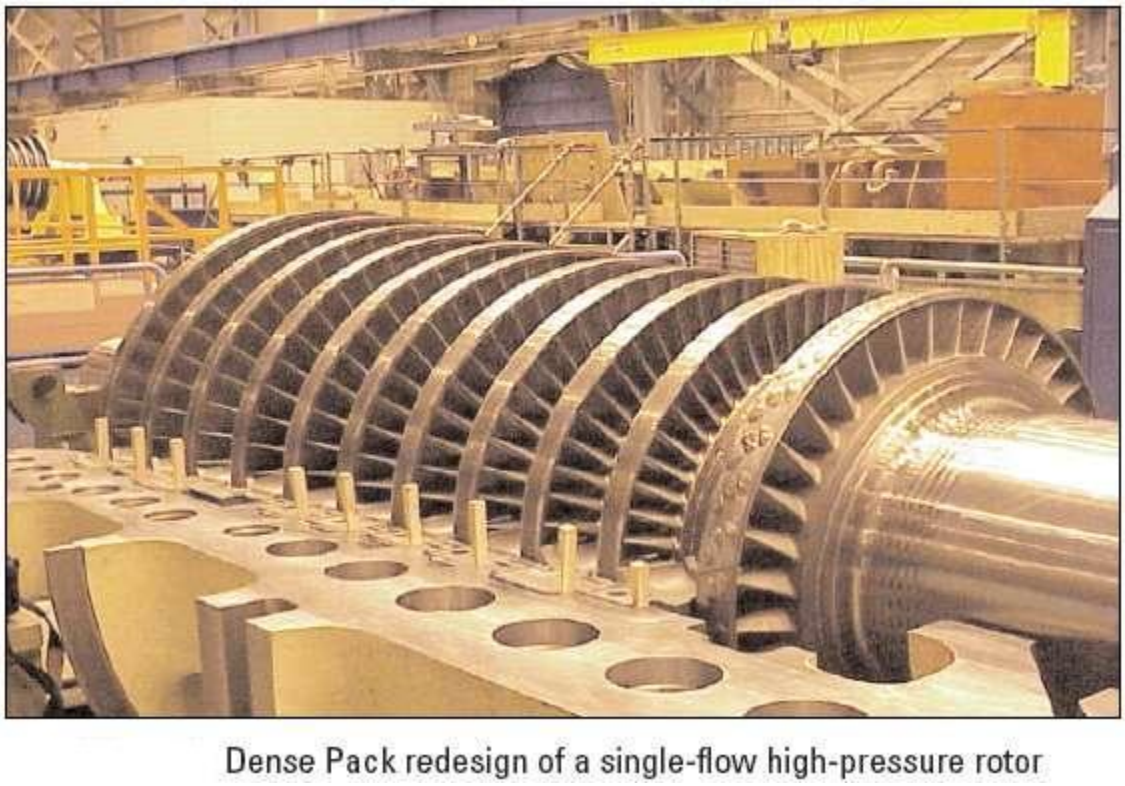



Figure 817. GE turbine upgrade program

# Chapter 29 Problems with Operation

## 1. What are some conditions that may prevent a turbine from developing full power?

The machine is overloaded.

The initial steam pressure and temperature are not up to design conditions.

The exhaust pressure is too high.

The governor is set too low.

The steam strainer is clogged.

Turbine nozzles are clogged with deposits.

Internal wear on nozzles and blades.

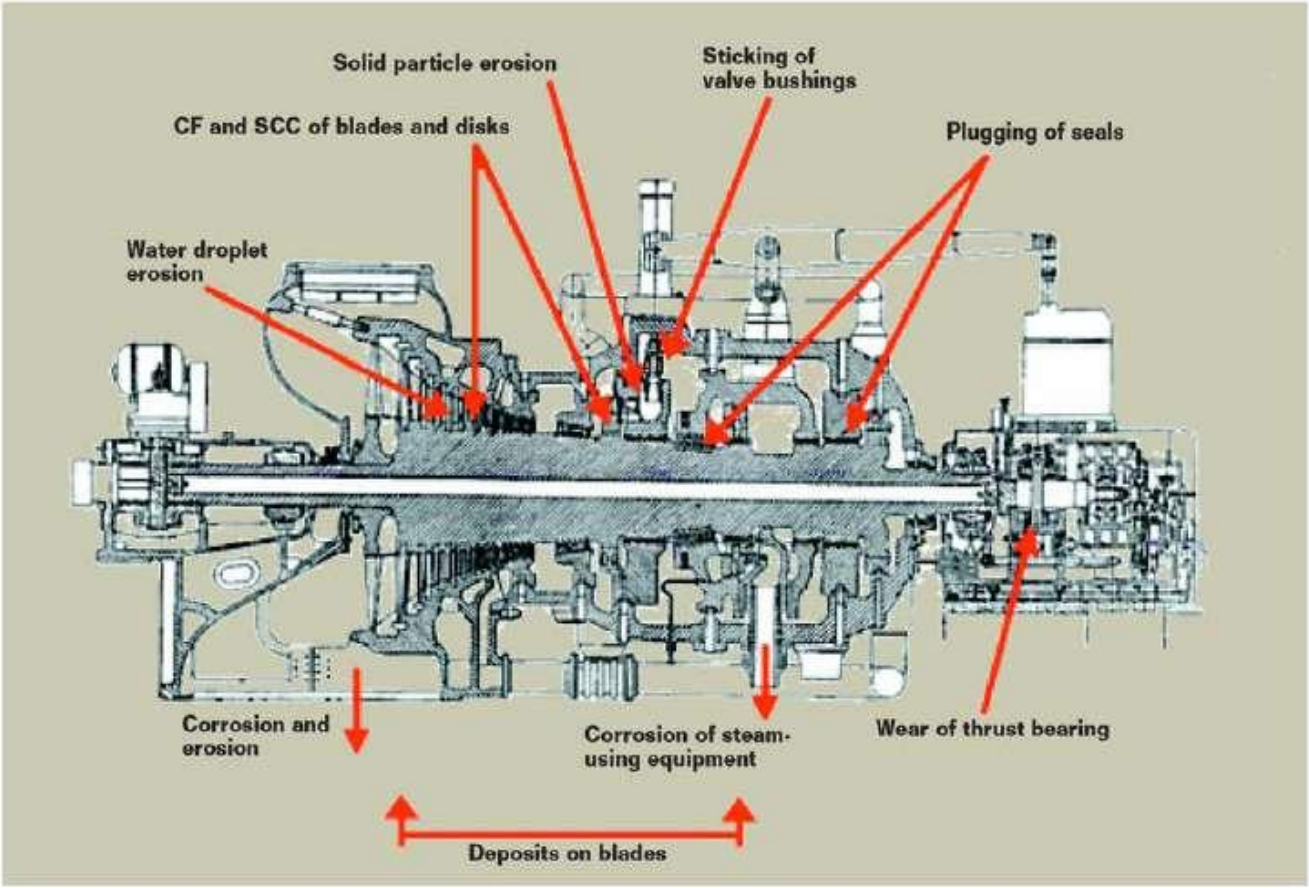



Figure 818. Problems encountered when operating turbines

## 2. What are the possible causes for the turbine not running at rated speed?

Possible causes are:

1. Too many hand valves closed,
2. Oil relay governor set too low,
3. Inlet steam pressure too low or exhaust pressure too high,
4. Load higher than turbine rating,
5. Throttle valve not opening fully,
6. Safety trip valve not opening properly,
7. Nozzles plugged,
8. Steam strainer choked.

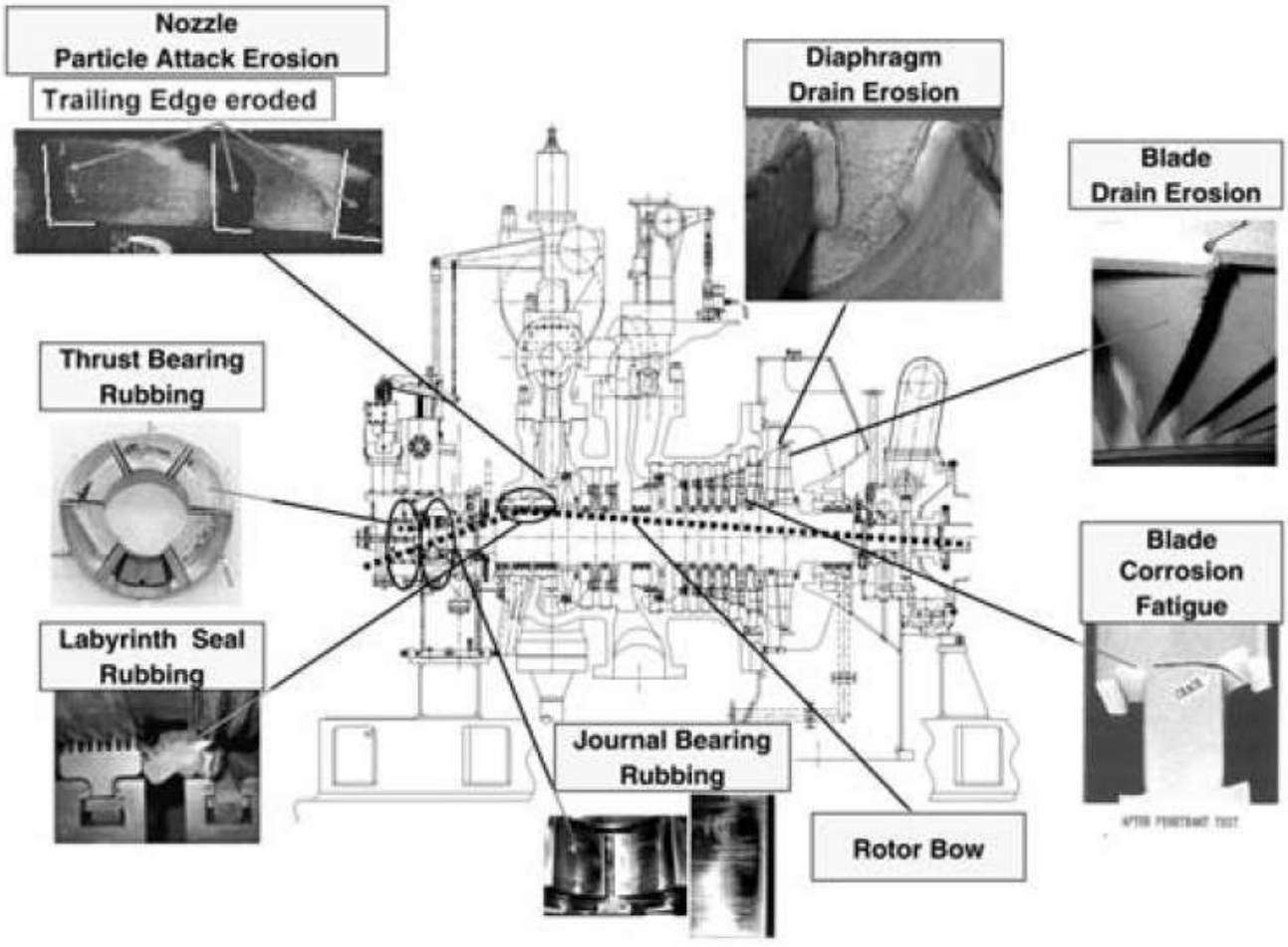



Figure 819. Other problems encountered when operating turbines

## 3. What are the losses in steam turbines?

Residual Velocity Loss - This is equal to the absolute velocity of the steam at the blade exit.

Loss due to Friction - Friction loss occurs in the nozzles, turbine blades and between the steam and rotating discs. This loss is about 10%.

Leakage Loss.

Loss due to Mechanical Friction - Accounts for the loss due to friction between the shaft and bearing.

Radiation Loss - Though this loss is negligible, as turbine casings are insulated, it occurs due to heat leakage from turbine to ambient air which is at a much lower temperature than the turbine.

Loss due to Moisture - In the lower stages of the turbine, the steam may become wet as the velocity of water particles is lower than that of steam. So a part of the kinetic energy of steam is lost to drag the water particles along with it.

## 4. What is the most prevalent source of water induction into a steam turbo-generator?

Leaking water tubes in feedwater heaters, which have steam on the shell side supplied from turbine extraction lines. The water at higher pressure can flow back into the turbine because the extraction steam is at a lower pressure. Check valves are needed on the steam extraction line to prevent the back-flow of water into the turbine.

## 5. What is the first sign of water carryover into the turbine?

The first sign would be an upsetting of stage - pressure distribution within the turbine at any given load. Turbine manufactures will supply stage - pressure characteristics for their multistage turbines, showing the steam pressures in various convenient stages for the entire range of turbine loads.

*S&V pages 130-131*

## 6. What could priming in a boiler do to a turbine?

Priming in a boiler is the carrying of water from the boiler to some point downstream. If the water makes it to the turbine the consequences would be disastrous.

## 7. What is meant by "thermal shocks"?

Sudden temperature changes are referred to as "thermal shocks" and will cause sudden unequal expansions, usually of a momentary duration.

Blockage congestion erosion

Erosion and Corrosion

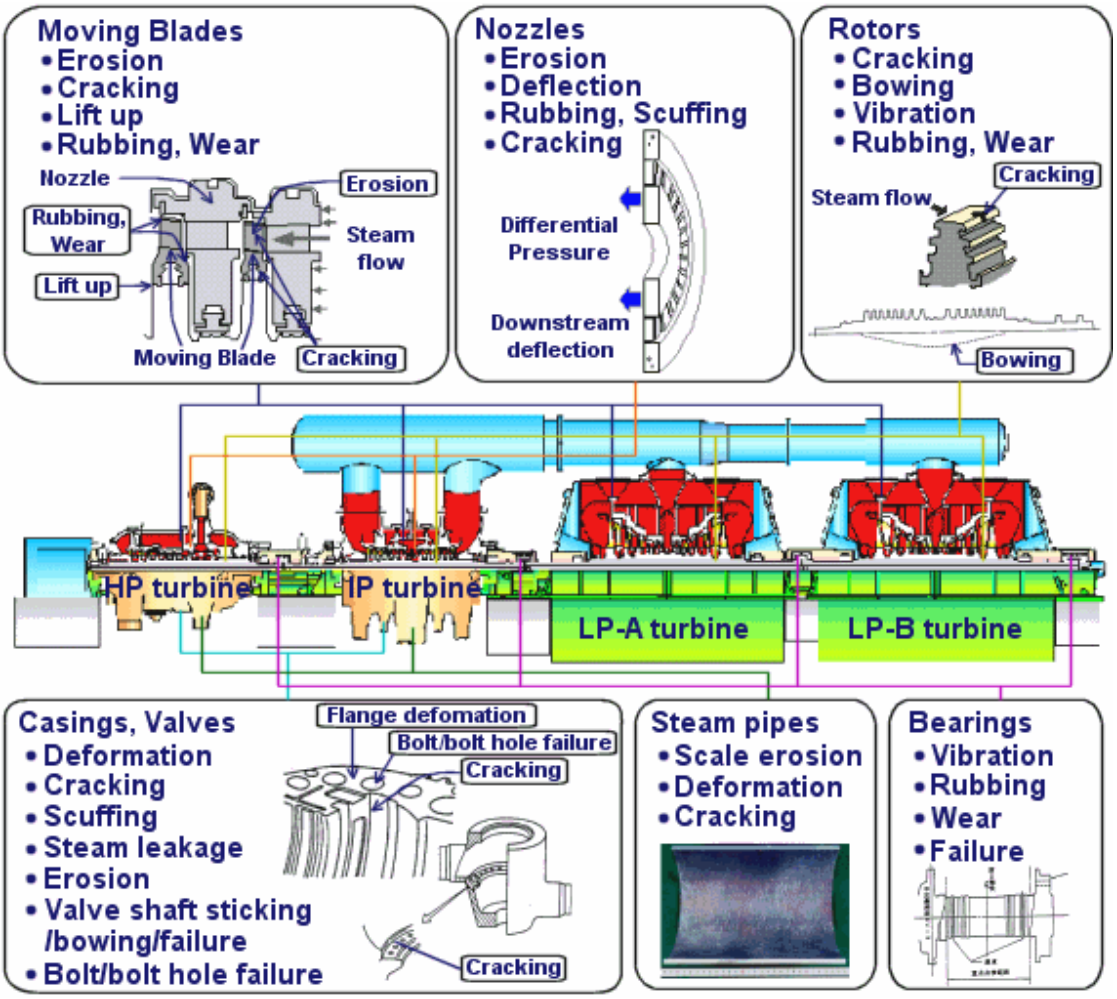



Figure 820. Problems the Turbine Operator must be aware of when operating the turbine

## 8. What are some of the conditions that must be guarded against in turbine operation?

Some of the conditions which must be guarded against are:

1. Unequal expansion

2. Vibration

3. Congestions

4. Lack of lubrication

5. Overspeeding

*S&V page 13*

On September 12, 2004, Seminole Generating Station Unit 2 experienced high turbine vibration between its intermediate pressure and high pressure turbines. This coal-fueled Putnam County base load station, celebrated its 20th year of commercial service in December 2004. Unit 2 was quickly removed from service to investigate the cause of the problem. Damaged blades were found in its intermediate pressure turbine. A subsequent inspection determined that three turbine blades had failed in the fourth rotating row in one of the intermediate turbine flow paths. As a result two rows of turbine blades required replacement.

## 9. What is the possible cause of slow start up of a steam turbine?

This may be due to high starting torque required by the driven equipment.

## 10. What are the possible causes of the speed of the turbine rotor increasing excessively as the load is decreased?

Throttle valve not closing fully.

Wearing of throttle valve seats.

Figure 821. This sticking admission valve led to an overspeeding turbine

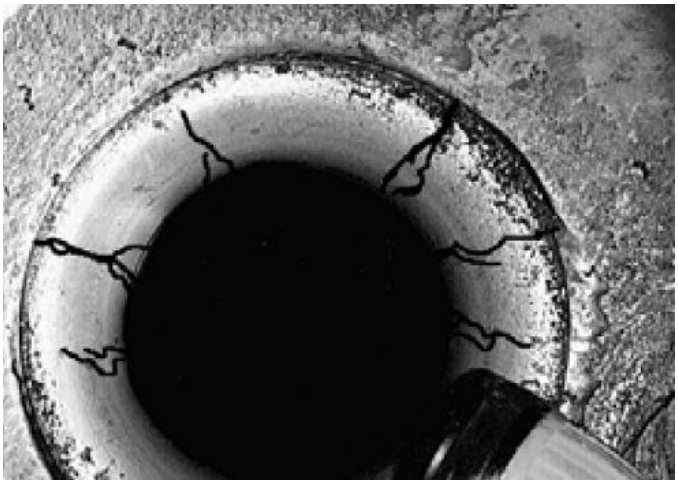


Figure 822. This admission valve seat has cracking that can let steam leak past the valve seat.

## 11. In which cases does erosion corrosion damage appear?

It is commonly encountered in nuclear steam turbines and old fossil-fuel-fired units that employ lower steam temperatures and pressures.

## 12. In which cases does moisture-impingement and washing erosion occur?

These are encountered in the wet sections of the steam turbine.

For nuclear power plants, these wet sections can involve parts of high-pressure cylinder.

Figure 823. Moisture erosion of turbine blades on the low pressure stage

## 13. What is water induction and what problems does it cause?

Induction of water into large steam turbines, a major cause of forced outages in recent years, has been addressed aggressively within the electric-utility industry. Among the consequences of such water induction:

1. Rub damage. Hard rubbing can cause extensive damage to turbine components such as packings, spill strips, buckets, covers and rotors.

2. Thrust-bearing failure. Ingress of water from the boiler may result in thrust loads much higher than design values, because of the greater fluid density and its impact against the rotor. A failure of the thrust bearing can result in excessive longitudinal travel of the rotor and subsequent severe axial rubbing damage to buckets, bucket wheels, diaphragms, packings, and other stationary components.

3. Bucket damage. Water ingested into the stages of a turbine through extraction lines may cause extensive impact damage to turbine buckets.

4. Thermal stress. Water contacting hot turbine parts can cause severe thermal stresses, particularly in thick components, possibly leading to low-cycle fatigue damage.

5. Permanent warping or distortion to diaphragms, valve parts, shells, casings, and rotors may result from water quenching. Example: Indiscriminate dumping of water into the condenser neck can cause severe chilling and distortion of low pressure turbine inner casings.

*Operating and Maintaining Steam Turbine / Generators. Powers Reprint 1976. page 5*

Figure 824. Water induction leads to blade damage

Figure 825. Water induction from a failure of the extraction trip can destroy rows of blades

Figure 826. Water induction can damage thrust bearings

## 14. Where is pitting corrosion mostly prevalent?

Upstream of LP stages as well as wet stages of LP cylinder.

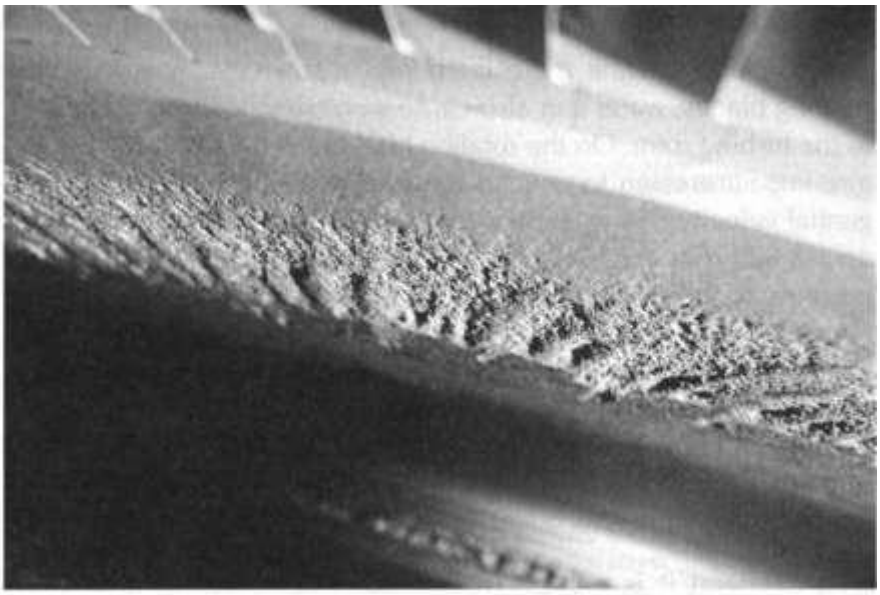


Figure 827. ***A wheel having been subjected to a combination of 'washing erosion' and 'corrosion'. The surface crevices have penetrated to a depth of about 0.150".***

## 15. What causes pressure in the steam chest to rise?

If you were running a turbine at an even load and boiler pressure for a length of time and the inlet pressure in the steam chest started rising, the reason is probably plugged nozzles. This is also known as congestion. In the majority of power plants it is necessary to treat feedwater to the boiler chemically in order to prevent the formation of scale on the boiler interior and in order to prevent corrosion. As steam bubbles break through the water surface in the boiler drum, they carry with them minute droplets of water which contains these dissolved chemicals. These droplets evaporate in the superheater, and the chemicals deposit on the valves, nozzles, and blades of the turbine, reducing the area available for steam flow. They also change the shape of the nozzle and blade passages.

*S&V pages 124. 125*

Figure 828. Buildup of deposits on turbine blades and diaphragms.

### 16. What does "turbine outage" mean?

"Turbine outage" means the turbine is out of service.

### 17. List some operating troubles that cause a falling off of efficiency.

1. Failure of interstage packing, sealing strips, or gland seals.

2. Failure of nozzles or blades.

3. Accumulation of chemical deposits on blades and nozzles.

### 18. How would you go about finding these troubles?

These troubles can be found by calculating the steam rate from watt-hour and flow meter records, or a quicker indication will be given by an upsetting of stage-pressure distribution within the turbine at any given load.

### 19. How often should turbines be overhauled or inspected? By whom?

Turbines should be overhauled every two years under the supervision of an experienced erection engineer.

Figure 829. Overhauling a turbine

Figure 830. Overhauling the turbine

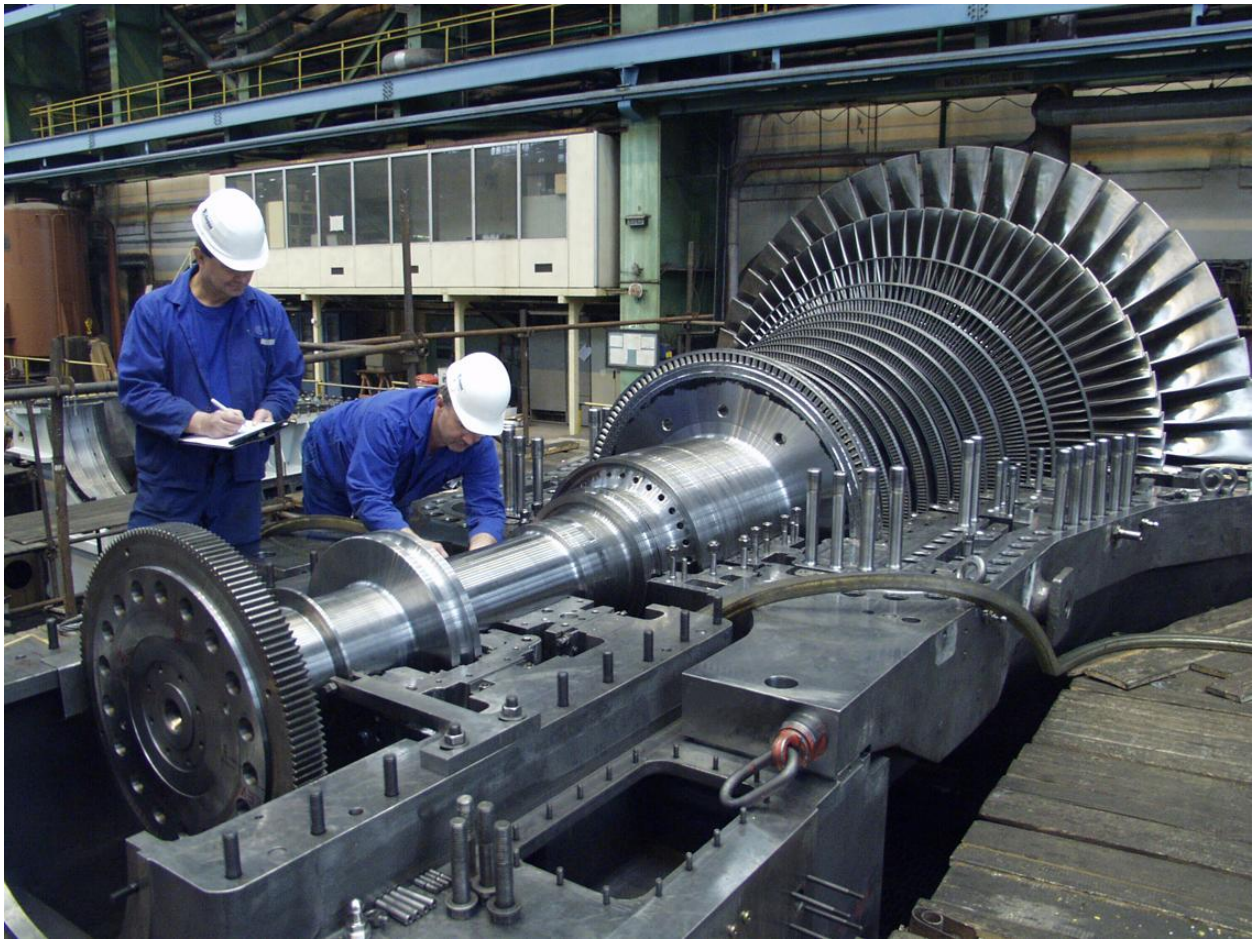


Figure 831. Checking clearances

Figure 832. Turbine Construction Shop

Figure 833. GE “Grand Canyon” construction shop

# Chapter 30 Turbine Explosions

**Hinkley Point**

On September 19th 1969 at the Hinkley Point 'A' nuclear power station (closed May 2000) in Somerset located in the southwest part of England, the No. 5 turbine generator suffered a catastrophic failure 33,360 hours after commercial service was started in April 1965. The failure was caused by spontaneous brittle facture of a shrunk-on low-pressure disc. The No.5 unit was disconnected from the grid for overspeed tests a few minutes before the accident. The failure occurred as the speed reached 3,200 rpm. The rotor shaft fractured completely in five positions, and three discs of the low-pressure The rotor came free from the unit. The cause is thought to be Stress Corrosion Cracking in a disc keyway. This was the first catastrophic failure of a turbine-generator caused by the brittle fracture of a rotating component in England.

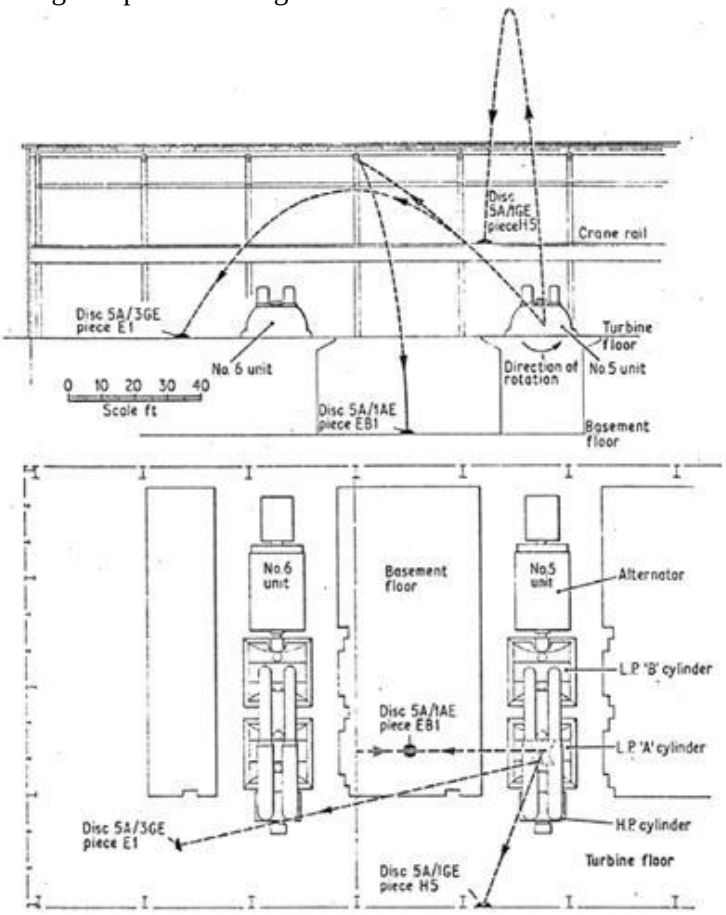



Figure 834. Flying-off paths of three large disc fragments

The low-pressure turbine disc, which was the site of the fracture, was made of Chrome Molybdenum steel by acid open hearth process. Also, the disc was found from chemical analyses to have a high sulfur and phosphorus content, although the levels were within the specifications. Thus, the material was apt to have lower fracture toughness as a result of the temper embrittlement caused during heat treatment process. Furthermore, in order to shrink the disc onto the shaft, the disc had a semicircular keyway that acted as a stress concentration reservoir. Under such conditions, the stress corrosion cracking related to environmental factors such as Sodium Hydroxide, also known as Lye or Caustic Soda in the steam can

occur, although it was very difficult to identify the true cause of the Stress Corrosion Cracking. Finally, when the crack reached only 6 tenths of an inch in depth, the brittle fracture of the disc occurred.

A number of operators who were watching the tachometer affirmed that the failure occurred as the rotation speed reached 3,200rpm. At the time, flames came out from the area of the low-pressure turbine together with a loud bang, and within a few seconds an explosion occurred. At the time of the accident, all six turbine-generators were operational. The No.4 and No.6 units were slightly damaged and were temporarily shut down. Fortunately, there were no casualties although seven operators were in the vicinity of the unit at that time.

The Stress Corrosion Cracking in the disc bore and keyway was observed on many other discs.

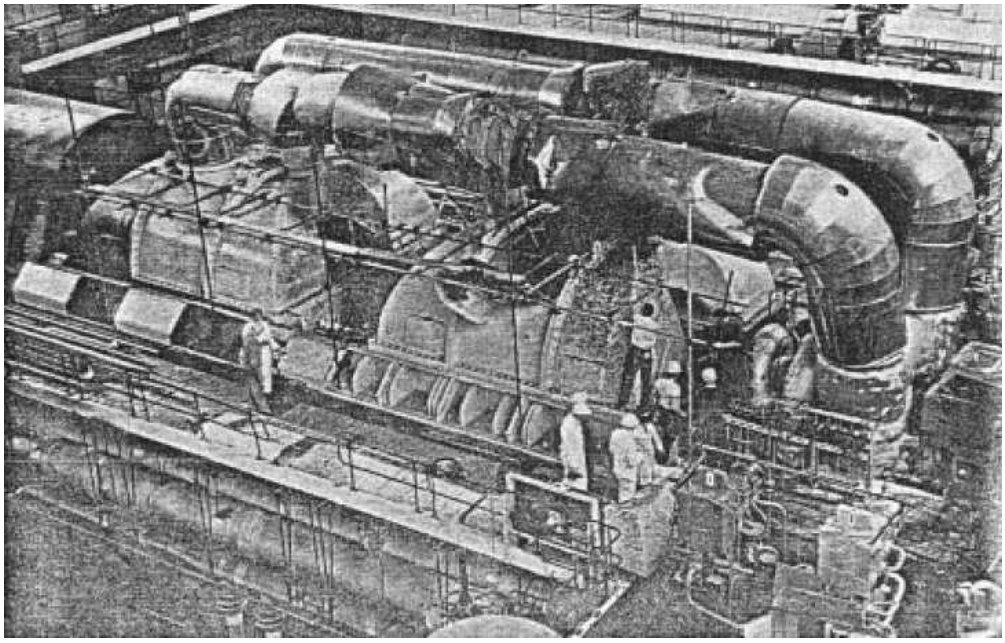


Figure 835. Hinkley Point Turbine after the blade excursion and subsequent explosion

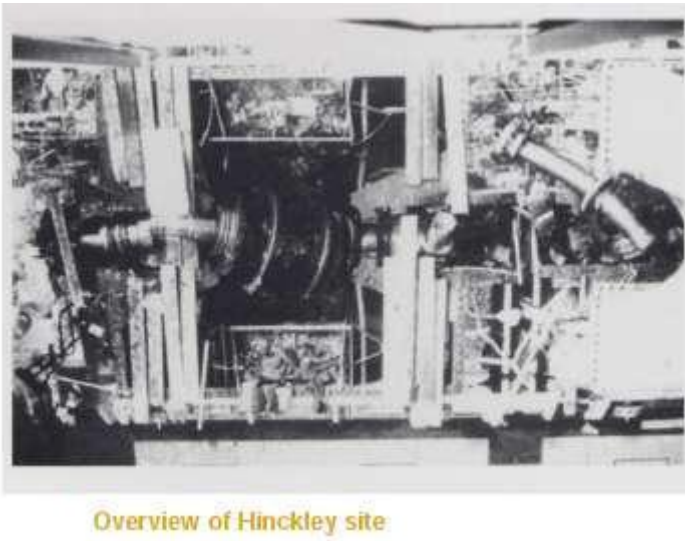



Figure 836. Overhead view of the Hinkley Site

Figure 837. The fire at Hinkley Point

During a recent 15-year period, 17 large turbine building fires resulted in more than $400 million in monetary loss. Lost generating capacity was in excess of 20 million Megawatts, which is roughly the equivalent of a mid-sized investor-owned utility in the United States. The average loss was $24 million and the average outage was more than 24 weeks.

**Witbank South Africa**

In January 2003, a 600-MW turbine generator at a power plant in Witbank, South Africa, suffered extensive mechanical and fire damage following the onset of severe vibration due to a turbine blade failure. While mechanical failure was the root cause, lube oil continued to flow and feed a fire for more than an hour, despite the fact the turbine stopped abruptly. The cost to rebuild the generator was significant and was scheduled to take about a year to complete. The cost to rebuild does not include the lost power generation revenue from the large generating plant.

The incident occurred upon start-up. One of the Low Pressure Blades (6.5 feet in length) broke off while the turbine was turning at 3000 rpm. The blade crashed through the casing (4 inches of solid steel), through the roof (65 feet higher up) and landed in the yard. The blade that broke took another 15 blades with it and the turbine went from 3000 rpm to standstill in a couple of seconds. The turbine/generator shaft broke clean at two different places. The ensuing fire was so hot that some of the roof's steel beams bent. The incident happened so quickly, that the vibration monitoring equipment did not even have a chance to pick anything up. Fortunately, this happened early in the morning when not many personnel were at work.

Figure 838. Turbine fire at Witbank, South Africa

Figure 839. Aftermath of the fire at Witbank

Figure 840. Pieces of the turbine lying about

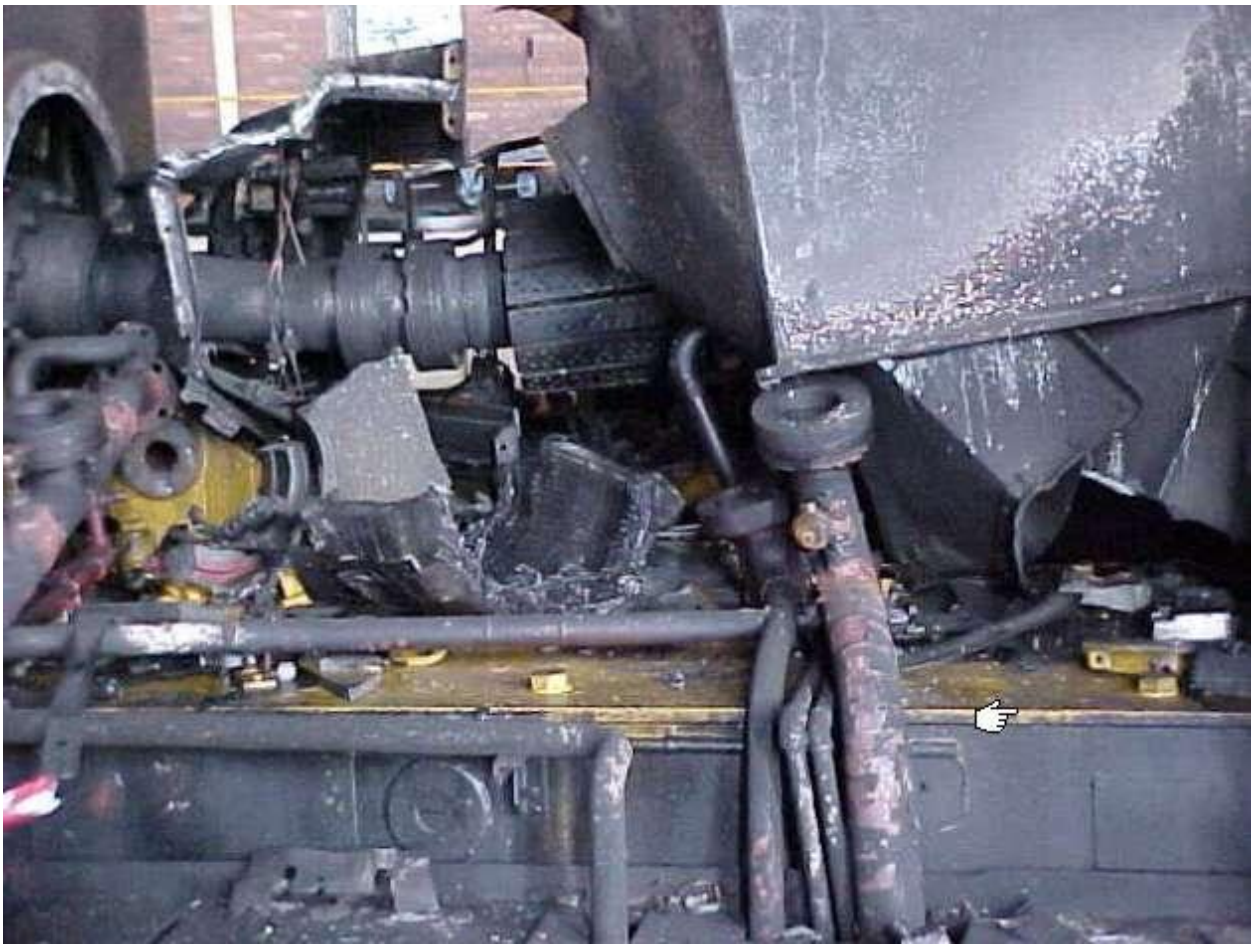


Figure 841. Rotors were bent or snapped in two

Figure 842. The generator was completely destroyed

**Fermi II blade failure Newport Michigan: Outage lasted from 12-25-1993 to Jan 18th 1995**

The catastrophic failure of the main turbine began the outage and determined its length. The plant had a history of high main turbine vibrations and had undertaken a series of refurbishments to upgrade the quality of the low pressure turbine blades. Rather than incur the cost of the refurbishments all at one time, management elected to do a little during each refueling outage. The main turbine catastrophically failed before the string of refurbishments could be completed. It took slightly over one year to repair the main turbine as well as repair the systems damaged by water, fires, and pieces flung from the turbine when it failed. The important point is that more aggressive management response to longstanding turbine problems likely would have prevented this extended outage.

History of Problems

*August 1988:* The main turbine automatically tripped on high vibration of the #8 and #9 bearings. The company attributed the high vibration levels to the failure of an air line that caused excessive cooling of the turbine lubricating oil.

*March 1989:* The reactor was manually shut down due to main turbine high vibrations. **Workers disconnected the circuit that would automatically trip the main turbine when vibrations rose too high**.

*September 1989:* During the first refueling outage, workers discovered broken blades and damaged blades in the low pressure turbines. Some of the pieces from the broken blades were not found. The 5th stage blades in all three low pressure turbines were removed. The 8th stage blades on all three low pressure turbines showed signs of excessive wear. Due to the unavailability of spare parts, only the 8th stage blades on low pressure turbine 1 were replaced. The plan was to refurbish the old 8th stage blades in low pressure turbine 1 and install them on low pressure turbine 2 during the second refueling outage. The old 8th stage blades from low pressure turbine 2 would be refurbished and installed in low pressure turbine 3 during the third refueling outage.

*December 1989:* The reactor automatically scrammed from 15 percent power when the main turbine tripped on high thrust wear on the turbine bearings. **Workers disconnected the trip on thrust wear**.

*November 25, 1990:* The reactor was shut down because of main turbine high vibrations. The NRC stated to the media, Detroit Edison "had more problems with turbine vibration at Fermi 2 than at the average plant. They've had vibration problems from the very beginning." Workers discovered broken blades in the 4th stage of low pressure turbine 3 and found that some of the broken pieces had damaged the adjacent shroud. The failures were attributed to stress from high loading on the 4th stage blades after the broken and damaged 5th stage blades were removed in September 1989. The 4th stage blades were removed.

*April 1991:* During the second refueling outage, workers installed redesigned blades in the 4th and 5th stages of all three low pressure turbines.8

*September 1992:* Blades scheduled to be replaced during the third refueling outage was deferred to the fourth refueling outage. The fourth refueling outage was scheduled to start in March 1994.

*August 13, 1993:* The reactor automatically scrammed from 93 percent power due to a false signal of high water level in the reactor vessel initiated as an operator was removing tape from a level instrument equalizing valve handle. Following the reactor scram, the reactor coolant system experienced an excessive cooldown rate (greater than 100 degrees F per hour) attributed to inadequate procedures and

simulator training, operator distractions caused by nearly **100 burned-out light bulbs on control room panels**, and stress from high operator work load. All of the control rods fully inserted during the scram, but six control rods failed to show full insertion due to burned-out light bulbs. After the false high water level tripped all of the feedwater pumps, an operator started the standby feedwater pump, but its injection valve did not show that it had opened due to a burned-out light bulb. Several containment isolation valves also did not show they had closed on the control room panel display due to burned-out light bulbs.

The operators were hindered in their attempts to monitor drywell pressure because its chart recorder in the control room had failed. The main steam isolation valves automatically closed due to the false high water level signal and the operators relied on the safety relief valves to control reactor pressure—but the safety relief valve tailpipes did not indicate high temperature due to burned-out light bulbs. When the main steam isolation valves were re-opened, **seven of the eight indicator lights failed to show "open" because the bulbs were burned out**.

*December 25, 1993:* The main turbine automatically tripped due to an erroneous mechanical overspeed signal caused by high vibrations. The reactor, which was operating at 93 percent power, received an automatic scram signal triggered by the turbine trip. The high vibration was caused by catastrophic failure of the turbine blades. Ejected blade parts ripped through the turbine casing and severed condenser tubes and other piping. The rupture of piping supplying hydrogen gas to the generator for cooling caused a large fire. The plant's fire brigade took 37 minutes to muster, dress, and enter the turbine building to fight the fire. Their efforts were hindered by numerous communication problems, including malfunctions of personnel motion detectors (e.g., "man down" alarms).

About 500,000 gallons of water from broken general service water piping and turbine building closed cooling water piping flooded the radioactive waste building basement to a depth of approximately six feet. Workers were slow to isolate the systems with broken piping to terminate the flooding, due to the total lack of procedures for a turbine building internal flood. The severed condenser tubes permitted water from Lake Michigan to flow into the condenser hotwell, from where it was pumped to the condensate storage tank. The standby feedwater system pumped water from the condensate storage tank to the reactor vessel. The lake water caused conductivity and chloride levels of the reactor vessel water to significantly exceed specifications.

Turbine generator: The event severely damaged the turbine and generator, as well as their support systems. This task was to repair or replace components as necessary to restore system functions.

Radiation waste systems recovery: The event generated a large volume of contaminated water that must be processed, including some containing 17,000 gallons of lubricating oil. This task covered treatment of the event's water and restoring the radioactive waste system to its design capability.

Condenser repair: The event severed condenser tubes and caused oil-laden water to fill the condenser hotwell. The tubes had to be repair the tubes and clean the condenser.

*March 16, 1995:* The reactor was shut down due to high turbine vibration levels. As a result of the catastrophic turbine failure on December 25, 1993, and the ensuing long outage, the turbine shaft developed bows. Workers attempted to counteract the effect of these bows by attaching "balance shots" to the turbine shaft similar to how mechanics attach weights to rims to balance wheels. But the balancing was complicated by the fact that the bows changed their shape as the metal shaft heated up, causing a balance shot properly positioned for a cold shaft to be in the wrong place for a heated shaft. Detroit Edison brought in Hopper & Associates, General Electric, and GEC Alshtom to diagnose the problem, but several weeks had passed without success in reducing the high turbine vibration levels.

Iranshahr

Location: Sistan & Baluchestan Iran

Operator: Iranshahr

Power Generation Management Co

Configuration: 4 X 64 MW

Operation: 1997-2004

Fuel: light fuel oil, heavy fuel oil

Boiler supplier: Brno

Turbine/Generator supplier: Skoda

Figure 843. Iranshahr Powerplant in Iran

EPC: Moshanir, Pilecar Group-Harrison, Azarab

Quick facts: In Jun 2004, the number four unit at Iranshahr power plant was commissioned. This plant has air cooled condensers.

Figure 844. The generator is completely destroyed. A likely scenario is that some sudden torque on the rotor caused the shaft to snap and fly through the powerplant, landing on the other side of a brick wall. The Hydrogen in the generator was instantly released and caused an explosion and fire, destroying most of the plant.

Figure 845. Another view of the generator

Figure 846. The aftermath of a hydrogen explosion in the generator

Figure 847. A piece of the shaft and coupling flew through the brick wall

Figure 848. The coupling bolts are sheared off and the shaft snapped in two becoming a flying missile, going right through the wall

Figure 849. Pieces of debris flew through the roof

Figure 850. The fire extended to the basement